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July 1979

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NATIONAL INTERREGIONAL COAL MODELS

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Old West Regional Commission
Bozeman, Montana
July 26-27, 1979

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16. ABSTRACT

The Great Plains Agricultural Council's Committee on Social and Economic Implications of Energy Extraction, Conversion and Transportation (GPC-8) organized and cosponsored with the Old West Regional Commission a Workshop on National Interregional Coal Models in Bozeman, Montana on July 26-27, 1979. Detailed information on six large-scale coal models were presented at the workshop, which was attended by about 30 modelers and analysts. The workshop was organized in response to widespread interest in learning more about currently available national interregional coal models. One goal of the meeting was to bring into sharper focus the problems associated with national interregional modeling, thus enhancing cooperative efforts by researchers in the Great Plains.

The models presented at the workshop were the U.S. Department of Agriculture Interregional Coal Analysis Model; the Argonne National Laboratory Coal Market Model; the Oak Ridge National Laboratory System of Models for Coal; the U.S. Geological Survey Short Run Coal Model; the ICF, Inc. Coal and Electric Utilities Model; and the Los Alamos National Laboratory ROCKY Model.

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The Old West Regional Commission is a Federal-State partnership designed to solve regional economic problems and stimulate orderly economic growth in the states of Montana, Nebraska, North Dakota, South Dakota and Wyoming. Established in 1972 under the Public Works and Economic Development Act of 1965, it is one of eight identical commissions throughout the country engaged in formulating and carrying out coordinated action plans for regional economic development.

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GREAT PLAINS AGRICULTURAL COUNCIL

History

Severe drought, dust storms, widespread crop failure and economic distress in the early thirties led agricultural leaders in the Great Plains to coordinate their efforts to combat the disaster. To meet a need that arose in this period, which included the handling of special funds, a Southern Great Plains Council was organized in 1937-38. The success of this Council in meeting the problems before it led to the organization of a Northern Great Plains Council in 1938.

These two Councils faced many common problems of how to bring about adjustments in land use, conservation of soil and water, and the adaptation of agriculture to the conditions of the Great Plains. Consequently they held joint meetings and subsequently consolidated in 1946 and became the Great Plains Agricultural Council. This provided a mechanism for continuous effort in adjusting agriculture to the variable conditions of the Great Plains. While considerable progress has been made much remains to be done. Because drought is a recurring phenomena and economic conditions change an organization is needed to give these problems continuous attention.

Purpose

The purpose of the Great Plains Agricultural Council is to provide an organization for effective cooperation on emerging Great Plains' problems. The specific functions of the Council are:

(a) To delineate and analyze the problems of Plains' agriculture.

(b) To suggest priorities in the attack on problems.

(c) To appraise the adequacy of existing research, education, and action programs in the Plains.

(d) To encourage the development of needed programs of research, education, and adjustment.

(e) To promote the adaptation of agricultural programs and policies to Plains' conditions.

(f) To promote cooperation in a coordinated attack on agricultural problems.

(g) To develop possible solutions to selected problems.

(h) To provide for the exchange of ideas between Washington and the field for solution of Plains' problems.

(i) To stimulate state and local participation in the study of agricultural problems and in the development of programs for solution.

The Council serves as a mechanism for the exchange of ideas and study of problems and its actions are not binding on any of its members.

Membership

The member agencies of the Council consist of: (1) interested agencies of the U.S. Department of Agriculture, and (2) the Agricultural Experiment Stations and Cooperative Extension Services of the Land Grant Colleges and Universities in the Great Plains States.

Organization

The Council: (a) Holds at least one Council meeting annually, (b) Names such committees as it deems advisable to carry out its objectives, (c) Reviews the work of the standing committees of the Council, and (d) Takes such other action as is deemed appropriate to carry out its objectives.

Most of the work of the Council is performed by committees. Member agencies may name a representative to any committee of the Council. Members usually name a representative only to the committees in which they have a special interest.

The standing committees of the Council are:

Research Committee
Extension Committee
Energy Committee
Forestry Committee
Resource Economics Committee
Water Resources Committee

The functions of the committees of the Council are:

1. To identify problems, each in his own field.
2. To suggest regional research.
3. To suggest multi-state extension programs.
4. To stimulate state research and extension programs.
5. To sponsor workshops as an aid in carrying out their functions.
6. To provide for coordination of related activities.

These are primarily "idea" committees of the Council and recommend research or extension programs, but do not undertake such programs themselves.

An administrative adviser is named by the Chairman of the Council, from among the membership of the Council, to maintain liaison with the standing committees of the Council. He submits an annual report to the Executive Committee on progress made during the year and on plans for the current year.

The Research Committee activates such research committees (GP projects) and research coordinating committees (GPC projects) as it deems necessary.

The Extension Committee activates and coordinates multi-state educational programs (GPE programs).

An administrative adviser is named from the membership of the Research and Extension Committees to maintain liaison with GP, GPC, and GPE committees and report progress to the Research and Extension Committees according to procedure manuals.

ABSTRACT

The Social and Economic Implications of Energy Extraction, Conversion, and Transportation Committee (GPC-8) of the Great Plains Council organized and cosponsored, with the Old West Regional Commission, a Workshop on National Interregional Coal Models in Bozeman, Montana in July, 1979. There were six large-scale coal models presented during the two-day workshop attended by approximately thirty modelers and analysts. Each presenter spent approximately three hours presenting and answering questions about his model and its application in policy analysis. The entire workshop was reported by a court recorder, typed, edited, reviewed, and presented to EPA for publication.

The models presented were the USDA Interregional Coal Analysis Model; the Argonne National Laboratory Coal Market Model; the Oak Ridge National Laboratory System of Models for Coal; the USGS Short Run Coal Model; the ICF Incorporated Coal and Electric Utilities Model; and the Los Alamos National Laboratory ROCKY Model.

ACKNOWLEDGMENT

Several people have contributed immensely to this volume and their effort should be acknowledged. First, Dr. Kenneth A. Blackburn for his effort in arranging for Old West Regional Commission support and for the Court Recorders, Charles Fisher and Ione T. Daniels, who, with dedicated effort, did a fine job of operating in an unfamiliar setting. My most sincere expression of gratitude, however, must be reserved for Maxine Rigdon, Jody Erickson and Peggy Reid. Maxine, our Office Manager, did a fine job supervising and editing this volume. Jody, our word processor operator, typed and retyped the manuscript several times without complaint. Peggy assisted in the tedious task of proof reading the entire manuscript. Finally, we wish to thank the Office of Environmental Engineering and Technology, Office of Research and Development, U.S. Environmental Protection Agency for their program and publication support.

John W. Green, Editor

Chairman, Great Plains Committee 8
Regional Economist and Project Leader
USDA-EPA Coal Use and Development Project
Natural Resource Economics Division
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U.S. Department of Agriculture

FOREWORD

The papers in this publication were presented at a workshop on "National Interregional Coal Models" held in Bozeman, Montana, July 26-27, 1979. The workshop was sponsored by the Great Plains Agricultural Council Committee on Social and Economic Implications of Energy Extraction, Conversion, and Transportation (GPC-8) and the Old West Regional Commission with additional support from the U.S. Department of Agriculture and the Environmental Protection Agency through their joint Coal Use and Development Project. The workshop was organized in response to widespread interest in learning more about currently available national interregional coal models and how they treat areas of interest to the sponsors. It was hoped that problems associated with national interregional modeling could be brought into sharper focus, thereby enhancing cooperative efforts by researchers in the Great Plains.

Each author was responsible for a two-three hour block of time on the program. This allowed for a comprehensive, indepth presentation and examination of each model. Models were presented by three of the Department of Energy regional laboratories, by the U.S. Geological Survey, by the U.S. Department of Agriculture, and by a private consulting firm. Overall, the papers described the current state of knowledge concerning national interregional coal models. The presentations and discussions pointed out the differences between approaches used to model national coal problems. The differences reemphasized the continuing need for research to produce workable models for solution of problems in an everchanging energy picture.

In summary, it was recognized that the job ahead for researchers and policy analysts is large, complex, challenging, and worth doing. Through sincere, unselfish cooperation between regional researchers and the Federal Government our ability to meet the challenge will be enhanced.

This workshop would not have been possible without the vital assistance of the Old West Regional Commission. The Commission provided and coordinated the services of a court recorder to report the verbatim proceedings of the workshop. When the recorder had typed the proceedings, Dr. Kenneth A. Blackburn of the Old West Regional Commission reviewed them before forwarding them to Dr. John W. Green, Secretary of the Great Plains Committee 8, who integrated (1) each author's presentation at the workshop, (2) the questions and answers pertaining to each presentation, and (3) the formal written papers provided to attendees prior to the workshop. The integrated manuscripts were sent to each author for review and revision. Dr. Green then put the six papers together with other information and sent the entire package to each author and other professionals for final review. Dr. Green then prepared the entire package for publication by the Environmental Protection Agency.

The ultimate responsibility for this publication must rest with Dr. Green and with each author. The information presented and the statements recorded do not represent official policy of the Environmental Protection Agency, the U.S. Department of Agriculture, the Old West Regional Commission or the Great Plains Agricultural Council.

TABLE OF CONTENTS

Old West Regional Commission-- i

Great Plains Agricultural Council----------------------------------- ii

  History--- ii
  Purpose--- ii
  Membership-- iii
  Organization-- iii

Abstract-- v

Acknowledgment-- vi

Foreword-- vii

List of Tables-- xii

List of Figures--- xiv

Agenda-- xvii

DEVELOPING AN INTERREGIONAL COAL MODEL---------------------------- 1

  Data Base--- 3
  Coal-producing Areas---------------------------------- 8
  Coal Preparation-------------------------------------- 20
  Transportation-- 23
  Power Plant Conversion-------------------------------- 33
  Demand-- 36
  Western States Report--------------------------------- 43
  Summary--- 48

ANALYSIS OF COAL DEVELOPMENT ISSUES WITH THE ARGONNE COAL MARKET MODEL-------------------------------------- 51

  Introduction-- 52

  Model Formulation------------------------------------- 52

  Data and Algorithms----------------------------------- 56

    Coal Supply--------------------------------------- 56
    Coal Demand--------------------------------------- 66
    Transport Costs----------------------------------- 69
    Environmental Control Costs----------------------- 70
    Data Integration---------------------------------- 72

  Previous Uses of the Model---------------------------- 72

    Bact Study-- 72
    Great Lakes Study--------------------------------- 77
    Gasifiers in Industry Study----------------------- 78

  References-- 83

THE OAK RIDGE SCOAL MODELS-- 85

Introduction-- 86

Factors Considered in the Development of SCOAL---------------- 87

A System of Coal Models---------------------------------- 87
Use of Physical Quantities-------------------------------- 89
Equity--- 91

Overview-- 92

National and Regional Siting Models-------------------------- 94

SCOAL Route Models-- 110

SCOAL Transport Models--------------------------------------- 117

SCOAL Transmission Models------------------------------------ 132

Extensions to the SCOAL Models------------------------------- 135

References-- 136

THE MARGINAL COST OF CONFORMING TO SULFUR EMISSION STANDARDS FOR COAL-- 137

Introduction--- 138
The Model-- 140
Results-- 148
Conclusions-- 157

References-- 159

THE COAL AND ELECTRIC UTILITIES MODEL: A RECENT APPLICATION------ 185

The Coal and Electric Utilities Model------------------------- 186

Capabilities--- 186

Model Structure-- 188

Supply Component-------------------------------------- 188
Coal Transportation------------------------------------ 191
Coal Piles--- 191
Utility Sector--- 193
Non-Utility Coal Demand-------------------------------- 193

Key Characteristics of CEUM---194
    Usable---194
    Understandable---195
    Flexible---195
    Equilibrium Solutions---196
    Resolution---197
    Price Sensitive---200

A Recent Application for the EPA---209

ROCKY1: AN ENERGY-ENVIRONMENT MODEL OF COAL AND ELECTRICITY SUPPLY---226

Abstract---227

Introduction---227

Basic Approach of ROCKY1---229

Unique Features of ROCKY1---233

Applications of ROCKY1---236
    Environmental Issues---237
    Economic Issues---237
    Energy Facility Location Issues---237
    Technology Policy Issues---237

Mathematical Structure of ROCKY1---237
    Indices---238
    Endogenous Variables---239
        Coal---239
        Transportation---239
        Electricity Generation---239
    Exogenous Variables: Policy, Fixed, Cost and Intermediate Variables---239
    Objective Function---240
    Constraints---240

Appendix A-Air Quality Methodology---241

Appendix B-Data Sources for Exogenous Variables---242

    Data Obtained from Others---242

    Data Obtained by ROCKY1 Project Staff---242

        Existing Capacity of Electricity Generating Plants in the Rocky Mountain West---242
        Cost of Operating Coal-Using Plants---242

LIST OF TABLES

DEVELOPING AN INTERREGIONAL COAL MODEL------------------------ 2

Table 1--Northern Great Plains Coal Production Areas-------- 9
Table 2--Supply Rows and Activities--for each CPA----------- 19
Table 3--Coal Preparation (Cleaning) Under Development------ 21
Table 4--Transportation From Each Supplier (By CPA) To Each Power Plant-------------------------------- 26
Table 5--Example Computer Output of Engineering Transportation Model------------------------------ 32
Table 6--Power Plant Conversion for Each Power Plant Site-- 34
Table 7--Demand--- 37

ANALYSIS OF COAL DEVELOPMENT ISSUES WITH THE ARGONNE COAL MARKET MODEL---------------------------------- 51

Table 1--Coal Reserves and Quality Characreristics by Major Mining Area---------------------------------- 61

THE MARGINAL COST OF CONFORMING TO SULFUR EMISSION STANDARDS FOR COAL-- 137

Table 1--State Coal Production in Million Tons, by Conformance Level---------------------------------- 150
Table 2--Mode and Conformance Percentage------------------ 156

Appendix A

Table 1--Utility Coal Flows by Origins and Destinations for 0% Conformance------------------------------- 161
Table 2--Utility Coal Flows by Origins and Destinations for Actual 1975 Conformance---------------------- 164
Table 3--Utility Coal Flows by Origins and Destinations for 1975 + 25% Conformance----------------------- 167
Table 4--Utility Coal Flows by Origins and Destinations for 1975 + 30% Conformance----------------------- 170
Table 5--Utility Coal Flows by Origins and Destinations for 1975 + 35% Conformance----------------------- 173

Appendix B

Table 1--1975 Actual Utility Coal Shipments--------------- 176

THE COAL AND ELECTRIC UTILITIES MODEL: A RECENT APPLICATION-- 185

Table 1--CEUM Coal Reserves Inputs by CEUM Coal Types---- 190

ROCKY1: AN ENERGY-ENVIRONMENT MODEL OF COAL AND ELECTRICITY SUPPLY-- 226

Appendix B

Table B-1--Capacity Factors for Electricity Generating Technologies Used in ROCKY1-------- 243
Table B-2--Levelized Annual Costs of Existing Electricity Generating Plants----------------- 244
Table B-3--Levelized Annual Cost of a New Coal Plant With Scrubbers------------------------- 244
Table B-4--Levelized Annual Cost of a New Nuclear Steam Plant------------------------------------ 245
Table B-5--Levelized Annual Cost of a New Oil/Gas Steam Plant------------------------------------ 245
Table B-6--Levelized Annual Cost of a New Hydroelectric Plant------------------------------- 246
Table B-7--Levelized Annual Cost of a New Lignite Plant and a New Oil/Gas Turbine Plant--------- 246
Table B-8--Existing Electricity Generating Capacity in the Rocky Mountain States----------------- 247
Table B-9--Sulfur Emissions From Coal Consumption Sectors-- 248

LIST OF FIGURES

DEVELOPING AN INTERREGIONAL COAL MODEL-------------------- 2

Figure 1--U.S. Power Plant Statistics 1975------------- 4
Figure 2--An example of the types of information included in the data base for the Model------ 6
Figure 3--Coal producing areas in the Western States--- 11
Figure 4--Coal producing areas in the Interior Region-- 12
Figure 5--Coal producing areas in the Appalachian Region--------------------------------------- 13
Figure 6--Coal producing areas in the Gulf Region------ 14
Figure 7--Coal producing areas in the Pacific Region--- 15
Figure 8--Midwest Coal Mine---------------------------- 24
Figure 9--Base Case Railroad Link with 10 Million Tons of Coal Per Year or More-------------------- 29
Figure 10-Transportation System Routines--------------- 31
Figure 11-Residential Electricity Consumption Forecast- 39
Figure 12-Proposed Residential Electricity Model (Cross-Section Data)------------------------ 42
Figure 13-Projected 1985 Coal Prices, Costs and Production------------------------------------ 44
Figure 14-Projected Western Coal Production and Remaining Reserves-------------------------- 46
Figure 15-Selected Alternative Scenario for 1985 3-Year Construction Delay in Power Plants to Use Western Coal------------------------- 47

ANALYSIS OF COAL DEVELOPMENT ISSUES WITH THE ARGONNE COAL MARKET MODEL-- 51

Figure 1--Geometric Description of Market Representation in QP Objective Function------ 55
Figure 2--Coal Supply Areas---------------------------- 57
Figure 3--Long-Run Coal Supply Functions--------------- 63
Figure 4--Demand Regions and Centroids (35 Demand Centers)------------------------------------ 68
Figure 5--Demand Regions and Centroids (98 Demand Centers)------------------------------------ 68
Figure 6--Argonne Coal Market Model Flowchart---------- 73
Figure 7--Dynamic Demand Adjustment-------------------- 74
Figure 8--Dynamic Supply Adjustment-------------------- 74
Figure 9--Changes in Interregional Coal Flows to Major Demand Areas Resulting from BACT Policy (Millions of Tons Shipped, 1990)------ 76

THE OAK RIDGE SCOAL MODELS-- 85

Figure 1--Flows of information in SCOAL-------------------- 93
Figure 2--Structure of MACRO 1, with predetermined source of coal for each potential power plant site--------------------------------------- 97
Figure 3--Structure of MACRO 2, with coal source and coal type for each potential power plant source to be chosen by the model----------------- 98
Figure 4--Structure of MACRONET 1 model for two load centers-- 105
Figure 5--Effect of number of interline transfers on route choice--------------------------------------- 113
Figure 6--Longhaul advantage to railroad initiating a shipment--- 115
Figure 7--Coal transport model #1, considering ton-miles only--- 120
Figure 8--Coal tansport model #2, considering coal quality and ton-miles---------------------------- 122
Figure 9--Coal transport model #3, considering coal type, ton-miles, and structure of transportation network------------------------------- 124
Figure 10-Coal transport model #4, with origin-destination pairs known and all routes available to connect each pair------------------ 128
Figure 11-Coal transport model #5, with origin-destination pairs known and routes to be selected from a previously determined subset of all possible routes---------------------- 129
Figure 12-Structure of SCOAL's electric transmission model--- 133

THE MARGINAL COST OF CONFORMING TO SULFUR EMISSION STANDARDS FOR COAL-- 137

Figure 1--Marginal Cost of Sulfur Removal for Cities with 750,000 Population----------------------- 151
Figure 2--Marginal Cost of Sulfur Removal for Cities with 250,000-750,000 Population----------------- 152
Figure 3--Marginal Cost of Sulfur Removal for Cities with 125,000-250,000 Population----------------- 153
Figure 4--Marginal Cost of Sulfur Removal for Cities with 125,000 Population----------------------- 154

THE COAL AND ELECTRIC UTILITIES MODEL: A RECENT APPLICATION--- 185

Figure 1--Structure of the ICF Coal and Electric Utilities Model--------------------------------- 189
Figure 2--Example Coal Supply Curve----------------------- 192
Figure 3--CEUM Supply Regions----------------------------- 198
Figure 4--CEUM Demand Regions----------------------------- 199
Figure 5--Issues--- 210
Figure 6--NSPS - The Decision------------------------------ 210

THE COAL AND ELECTRIC UTILITIES MODEL: A RECENT APPLICATION (continued)

Figure 7--Washing Credits-- 211
Figure 8--Rationale for CAP-------------------------------------- 212
Figure 9--Comparison of Scrubber Cost Estimates------------- 212
Figure 10-Alternative Standards------------------------------ 214
Figure 11-Summary of National Emissions and Costs for 1995 of Alternative Standards------------------- 215
Figure 12-National Emissions and Costs for Alternative Standards in 1995---------------------------------- 216
Figure 13-National Emissions - 1995------------------------ 217
Figure 13-Regional Emissions - 1995------------------------ 219
Figure 15-Costs--- 219
Figure 16-National Emission Trends------------------------- 221
Figure 17-Regional Coal Production - 1995------------------ 222
Figure 18-Appalachian Coal Production - 1995--------------- 224
Figure 19-Western Coal Production - 1995------------------- 224
Figure 20-ICF Consumption Forecast------------------------- 225
Figure 21-ICF Production Forecast-------------------------- 225

ROCKY1: AN ENERGY-ENVIRONMENT MODEL OF COAL AND ELECTRICITY SUPPLY-- 226

Figure 1--Electricity Demand Regions----------------------- 230
Figure 2--ROCKY1 Coal Supply Regions----------------------- 231
Figure 3--Potential Sources of Imported Baseload Electricity for the Southern California Market---- 232
Figure 4--ROCKY1 Coal Demand Regions----------------------- 233
Figure 5--Arizona's Air-Basin Regions---------------------- 234
Figure 6--Class I Areas with 75-km Buffer Zones------------- 235
Figure 7--Arizona's High Ground, Class I Areas, and Buffer Zones--------------------------------------- 236

AGENDA
GREAT PLAINS COMMITTEE 8 SUMMER WORKSHOP
BOZEMAN, MONTANA
July 26-27, 1979

July 26 - Thursday

8:00 AM	Opening Remarks Larry Leistritz, Chairman John W. Green, Secretary and Workshop Coordinator
8:30 - 11:00 AM	The EPA-USDA Interregional Coal Analysis Model John W. Green NRED-ESCS-USDA Ft. Collins, CO 303/482-9279
10:00 - 10:30 AM	Coffee
11:00 AM - 2:00 PM	The Argonne Coal Market Model Charles M. Macal Energy and Environmental Systems Division Argonne National Laboratory Argonne, IL 312/972-7476
12:00 - 1:00 PM	Lunch
2:00 - 5:00 PM	The Oak Ridge SCOAL Models Ed Hillsman and Rick Church Regional and Urban Studies Section Energy Division Oak Ridge National Laboratory P.O. Box X Oak Ridge, TN 37830 615/574-5938
3:00 - 3:30 PM	Coffee
5:00 PM	No host cocktail hour

July 27 - Friday

8:00 - 10:00 AM	Domestic Coal Distribution: An Analysis of Coal Transportation and Extraction Costs Rich Bernknopf Office of the Director U.S. Geological Survey Reston, VA 703/806-7435
10:00 - 10:30 AM	Coffee

10:30 AM - 12:30 PM	The ICF Coal and Electric Utilities Model C. Hoff Stauffer, Jr. Daniel E. Klein ICF Incorporated Washington, D.C. 202/862-1100
12:30 - 1:30 PM	Lunch
1:30 - 3:30 PM	ROCKY: An Optimization Model of Coal Demand and Electricity Generation Verne Loose Robert Bivins Charles Kolstad Los Alamos Scientific Laboratory Los Alamos, NM 505/667-2113
3:30 PM	Discussion and wrap-up Adjourn

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July 26-27, 1979
Bozeman, Montana

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July 26-27, 1979
Bozeman, Montana

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DEVELOPING AN INTERREGIONAL COAL MODEL

by

John W. Green

Natural Resource Economics Division
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Fort Collins, Colorado

DEVELOPING AN INTERREGIONAL COAL ANALYSIS MODEL

by

John W. Green [1]

The energy picture in the United States is constantly changing. Uncertainty over the economic advantages of using different fuels has caused concern about the location and intensity of energy developments. Development has already created serious problems in the western United States where coal mining has expanded rapidly for several years. Impacts on some rural communities have been severe. These and other concerns are responsible for continued policy analysis by the Environmental Protection Agency (EPA) and the U.S. Department of Agriculture (USDA). The Interregional Coal Analysis Model (ICAM) is part of that effort.

The NRED is developing an interregional competition model to systematically assess the impacts of policy decisions on the level of coal development in small regions of the United States. The model integrates information contained in coal-producing region profile reports being developed by the research team, data from other analytical models, and other information necessary to analyze alternative scenarios. Contracts have been awarded to provide water resource information, transportation movement and capacity analysis, reclamation data, and demand information.

This paper is a description of the interregional competition model. It describes the structure of two models. The 1975 model reflects the coal mining, transportation, and generation situation which existed in 1975. It develops a base solution against which alternative scenario solutions are compared. The 1985 model portrays the situation most likely to exist in 1985. It also develops a base solution for use in comparing alternative scenarios.

---

[1] John W. Green is a Regional Economist with the Natural Resource Economics Division (NRED), Economics and Statistics Service (ESS); USDA; located in Fort Collins, Colorado.

Data Base

During the early stages of this project we reviewed other available interregional competition models. It was our objective to assess the impacts of coal mining and electric generation development in rural areas. We found that the regional detail in existing models was insufficient to meet our objectives. We consequently decided to develop our own disaggregated data base and model.

This detailed level of disaggregation involves examining each individual large coal-fired power plant (100 megawatts and over) and determining individual mine suppliers for each of them. The process of examining each large coal-fired power plant and its individual suppliers enables us to assess specific community impacts for alternative scenarios.

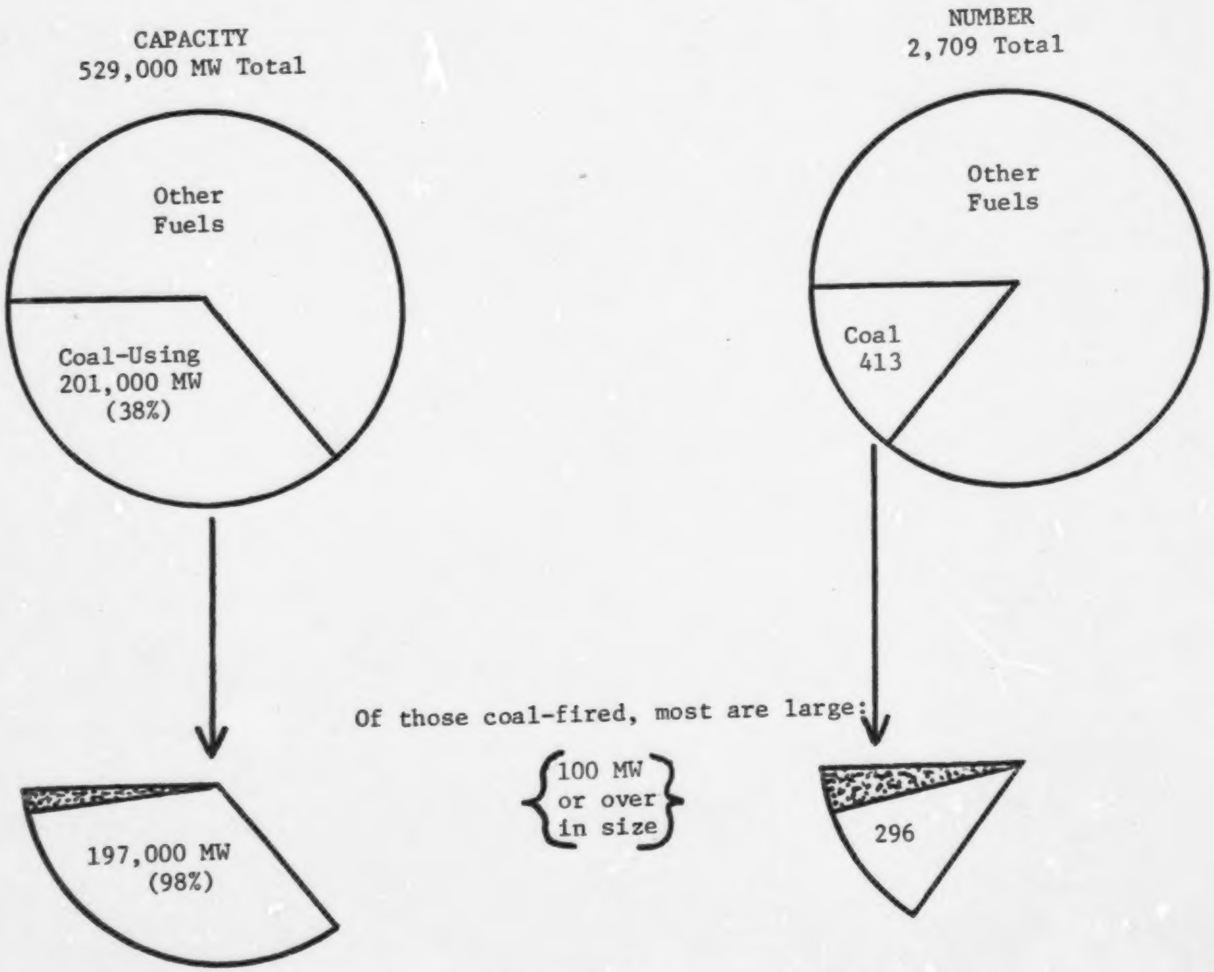
The limitation of our data base to coal-fired power plants 100 megawatts and larger resulted in a loss of only 2 percent of the 1975 U.S. coal-fired capacity. Figure 1 describes the analysis we conducted to make this determination.

Q. George Ferrell. Is that 2 percent of the number of power plants or 2 percent of capacity?

A. Two percent of capacity.

There were 529,000 megawatts of electrical generating capacity in the United States in 1975 of which 201,000 megawatts, or 38 percent, was coal fired. There were 2,709 power plants in the United States in 1975 and 413 were coal fired. Two hundred ninety-six (296) of the 413 coal-fired power plants were

Figure 1 --U.S. POWER PLANT STATISTICS 1975



296 plants of 100 MW or over account for 98% of coal-fired capacity.

100 megawatts or over in size. These 296 power plants totaled 197,000 megawatts. This was 98 percent of the coal-fired generating capacity in 1975. Therefore, by reducing the number of coal-fired power plants to include only those 100 megawatts or larger we sacrificed only 2 percent of the coal-fired generating capacity.

The level of detail in our data base is even more clearly defined by Figure 2 which uses the Baldwin Power Plant as an example. The Baldwin plant is located in Baldwin, Illinois and is a 1,892 megawatt plant. In 1975 it produced 8,633 million kilowatt hours of electricity. Its conversion ratio was 9,627 Btu per kilowatt hour of electricity produced. The Baldwin plant is wholly owned by Illinois Power Company. The mix of customers served by Illinois Power Company was used to develop our residential econometric demand model.

The Baldwin plant received coal from four sources in 1975. It received 1.95 percent from Coal Producing Area (CPA) Wyoming 3 (WY03), 0.12 percent from CPA Utah 1 (UT01), 81.35 percent from CPA Illinois 5 (IL05), and 16.58 percent from CPA Illinois 6 (IL06). We have determined the individual mine(s) in each CPA which supplied the Baldwin plant. The Baldwin plant used 4,168,350 tons of coal in 1975. Some of the coal used by the Baldwin plant was processed by preparation plants to reduce the sulfur and ash content and increase the Btu value. We will attempt to monitor this in our model.

The preparation plant(s) processing the coal-used water as did the Baldwin Power Plant. They both used approximately 18,244 acre-feet of water in 1975. They also used more than 1,036 tons of chemicals.

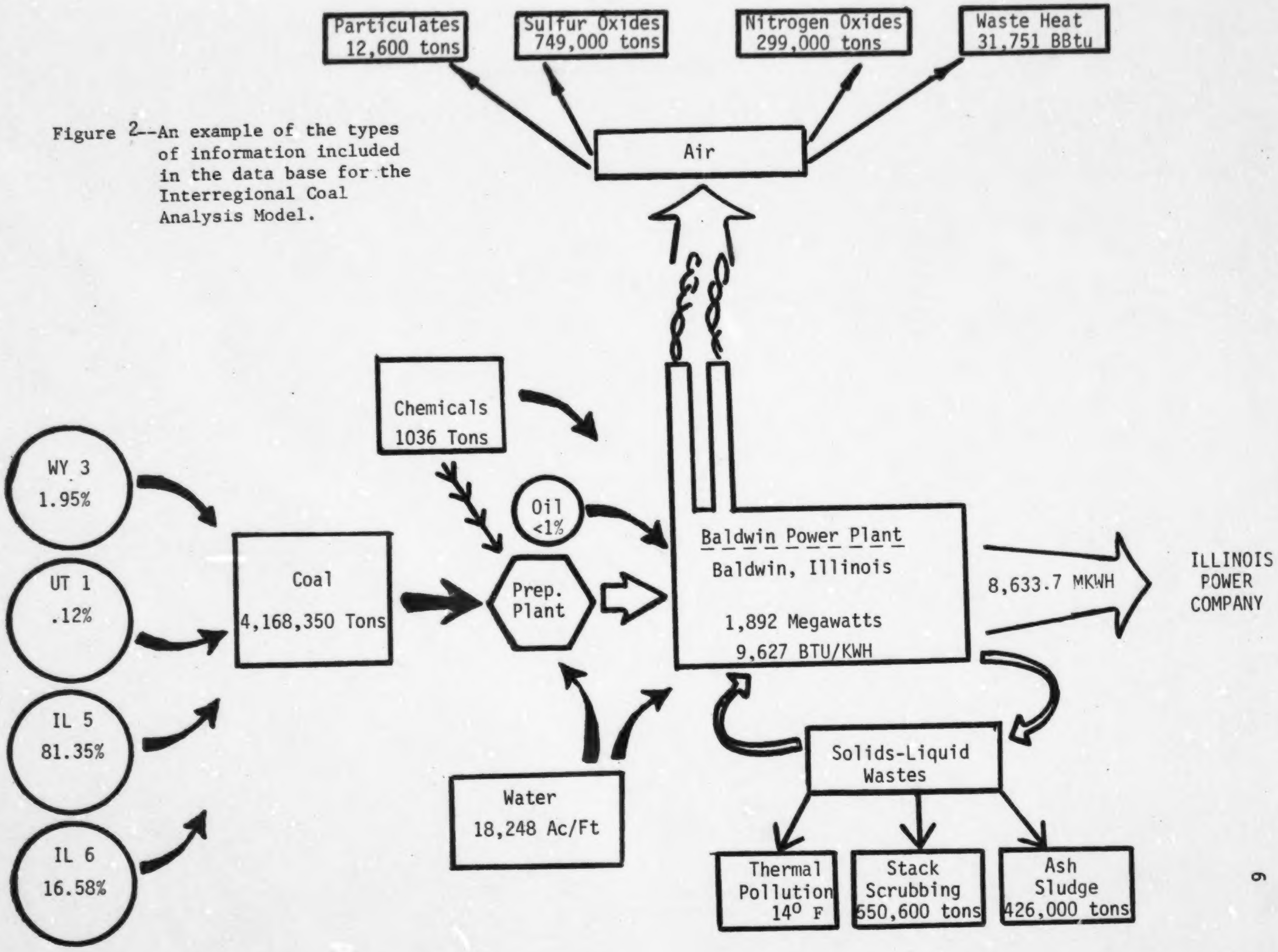

Particulates
12,600 tons
Sulfur Oxides
749,000 tons
Nitrogen Oxides
299,000 tons
Waste Heat
31,751 BBtu
Air
Chemicals
1036 Tons
WY 3
1.95%
UT 1
.12%
IL 5
81.35%
IL 6
16.58%
Coal
4,168,350 Tons
Oil
<1%
Prep.
Plant
Baldwin Power Plant
Baldwin, Illinois
1,892 Megawatts
9,627 BTU/KWH
8,633.7 MKWH
ILLINOIS
POWER
COMPANY
Water
18,248 Ac/Ft
Solids-Liquid
Wastes
Thermal
Pollution
14° F
Stack
Scrubbing
550,600 tons
Ash
Sludge
426,000 tons

Figure 2--An example of the types of information included in the data base for the Interregional Coal Analysis Model.

The Baldwin Power Plant produced both solid and liquid wastes. The thermal water pollution from this plant (the temperature increases across the condensers) was 14° F. Its stack scrubbing system produced 550,600 tons of solids. There were 426,000 tons of ash sludge produced. The Baldwin plant also produced air pollution consisting of 12,600 tons of particulates, 749,000 tons of sulfur oxides, 299,000 tons of nitrogen oxides, and 31,751 billion Btu of waste heat.

Q. Does the figure on sulfur oxides seem high if you start with only 4 million tons of coal?

A. This question points out one of many data problems. This information comes from Form 67 published by the Energy Information Administration, DOE. There is substantial error in that data which we are working to correct. We are comparing data from 1969 through 1976 in an attempt to flag all errors. Many plants reported the same data for multiple years even though their reliability factors changed. We are cooperating with Brookhaven National Laboratory and the EPA to use other data bases to make accuracy checks.

Figure 2 is an example of the level of detail we track in our data base and model. We monitor, for each plant, where it obtained its coal and how that coal was prepared and transported to the plant. We determine the amount of raw materials used in both preparation of the coal and the burning of it in the plant. We monitor the water used and the solid, liquid, and air pollutants produced. We ascertain the ownership of the power plant and distribute the electricity produced based on its ownership.

Q. Do you also use Form 423 data to determine coal shipment sulfur contents?

A. Yes. We started with Bureau of Mines regions from 1975 Form 423 data. Only approximately 65 percent of the mine sources were reported so we went to Washington and looked at the completed forms in an attempt to fill in missing mine sources. This was only partially successful. Consequently, we have used any other source we can find, including calling the power plant, to fill in the missing data elements. We estimate that approximately 20 percent of the data for 1975 is missing or incorrect. The data gets much better after 1975.

Q. Jerry Eyster. Have you attempted to compare emissions data from Form 67 with sulfur content data from Form 423?

A. That's part of the procedure being used to verify Form 67 data. We have performed water and material balances for each power plant to ascertain whether reported data is approximately correct. We enlisted the aid of an engineer at Colorado State University to help us structure the balance equations.

Q. Jerry Eyster. Is that being mechanized?

A. It is all being done on the computer. We have concentrated on the water balance equations but the material balance equations have been written. We have found some power plants that the data reports to be producing water. We could use more of these in the West!

Coal-producing Areas

Virgil Whetzel is responsible for writing regional reports which describe coal supply in each of six geographic regions in the United States. He is responsible for aggregating counties into homogeneous coal-producing areas (CPAs). These homogeneous coal-producing areas are delineated by examining the characteristics of the coal reserves in each county.

Table 1 shows the CPAs in the Northern Great Plains. There are five CPAs in Montana, one in South Dakota, three in North Dakota and four in Wyoming. The Colstrip area is MT04 and the Gillette, Wyoming region is WY02. We are using this CPA level of aggregation for many purposes in our model but we are also identifying individual mine sources for the coal delivered to each power plant. This is necessary in order to specify origin and destination points for the transportation model.

TABLE 1. NORTHERN GREAT PLAINS COAL PRODUCTION AREAS

Montana		
MT1		
	46	Sheridan
MT2		
	11	Dawson
	13	Fallon
	42	Richland
	43	Roosevelt
	55	Wilbaux
MT3		
	28	McCone
	40	Prairie
MT4		
	02	Bighorn
	17	Garfield
	33	Musselshel
	44	Rosebud
	52	Treasure
MT5		
	09	Custer
	38	Powder River
South Dakota		
SD1		
	15	Carson
	20	Dewey
	31	Harding
	52	Perkins
North Dakota		
ND1		
	07	Burke
	12	Divide
	25	McHenry
	27	McKenzie
	28	McLear
	31	Montrail
	51	Ward
	53	Williams
North Dakota		
ND2		
	04	Billings
	08	Burleigh
	13	Dunn
	17	Golden Valley
	29	Mercer
	30	Morton
	33	Oliver
ND3		
	01	Adams
	06	Dowman
	19	Grant
	21	Heltinger
	44	Slope
	45	Stark
Wyoming		
WY1		
	17	Sheridan
WY2		
	03	Campbell
	10	Johnson
WY3		
	04	Carbon
	05	Converse
WY4		
	12	Lincoln
	19	Sweetwater

Figure 3 shows the CPAs in the Northern Great Plains and Rocky Mountain States. These CPAs are used in the Western States Report being published. In addition to the CPAs in the Northern Great Plains, there are three CPAs in Utah, seven in Colorado, one in Arizona, and four in New Mexico.

Figure 4 shows the CPAs in the Interior region. Western Kentucky is in the Interior region while eastern Kentucky is in the Appalachian region. There are two CPAs in Iowa, six in Illinois, three in Indiana, one in Kentucky, five in Missouri, three in Kansas, three in Oklahoma, and one in Arkansas. As can be seen by examining Iowa and Kansas, the CPAs do not have to be contiguous groupings of counties.

Figure 5 shows the CPAs in the Appalachian region. There are four in Ohio, two in Pennsylvania, one in Maryland, six in West Virginia, six in eastern Kentucky, two in Tennessee, and one in Alabama. Figure 6 shows the CPAs in the Gulf region. There are three in Texas, one in Arkansas, and one in Alabama. The Pacific region (Figure 7) shows three CPAs in Washington and four in Alaska.

Q. Lowell Smith. The coal-producing regions shown were producing in 1975; they might not correlate with the location of reserves and the location of production in 1984 or 2000.

A. That is correct. However, we monitor individual mine suppliers for each existing and new power plant. We can reaggregate into new CPAs if necessary. Existing suppliers located outside a CPA are assigned to a State CPA which includes all counties not located in numbered CPAs. We have taken the CPA shortcut to keep the size of the simulation model manageable.

Q. Verne Loose. Did you allow the supply patterns to change from the base period, the optimization period?

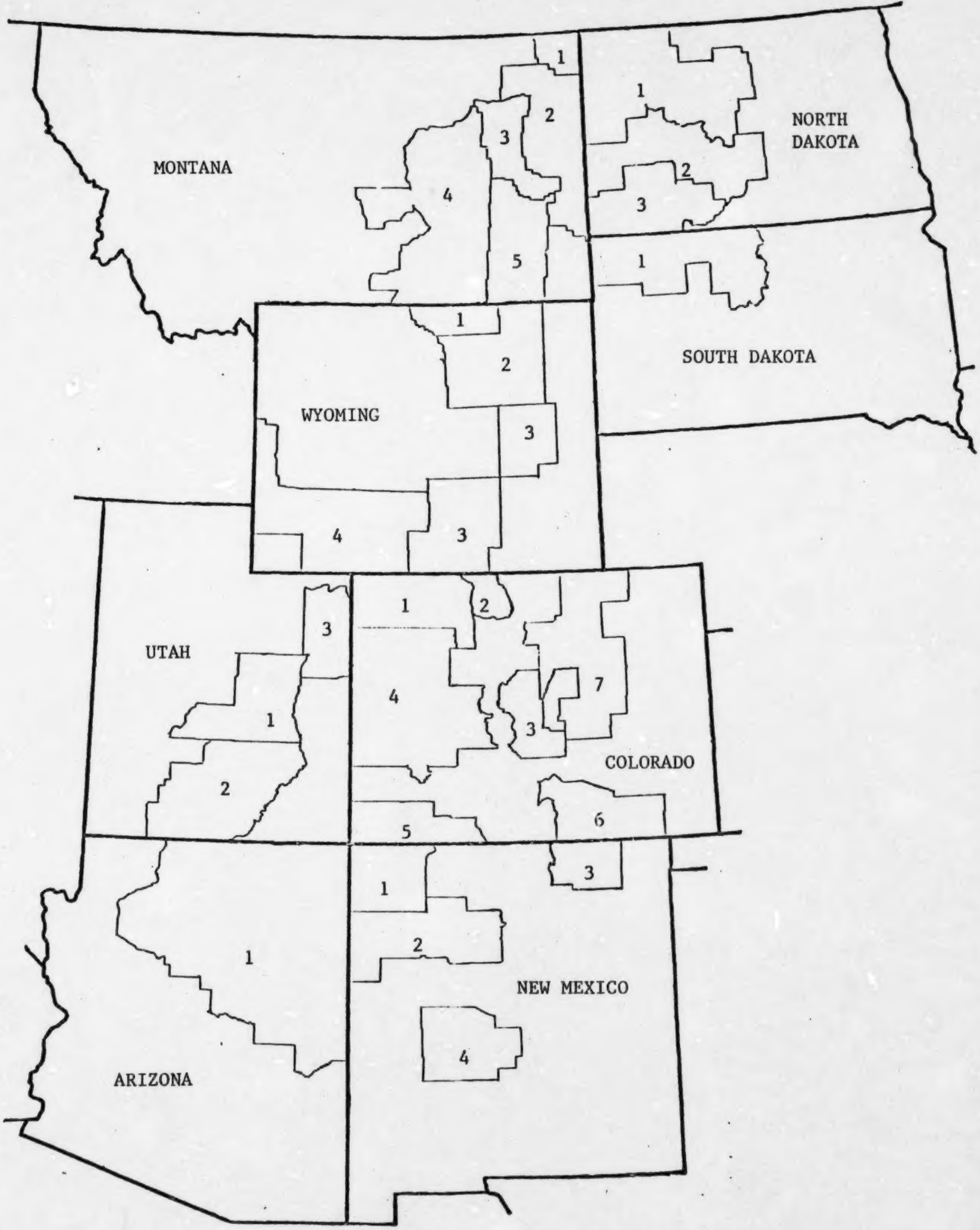
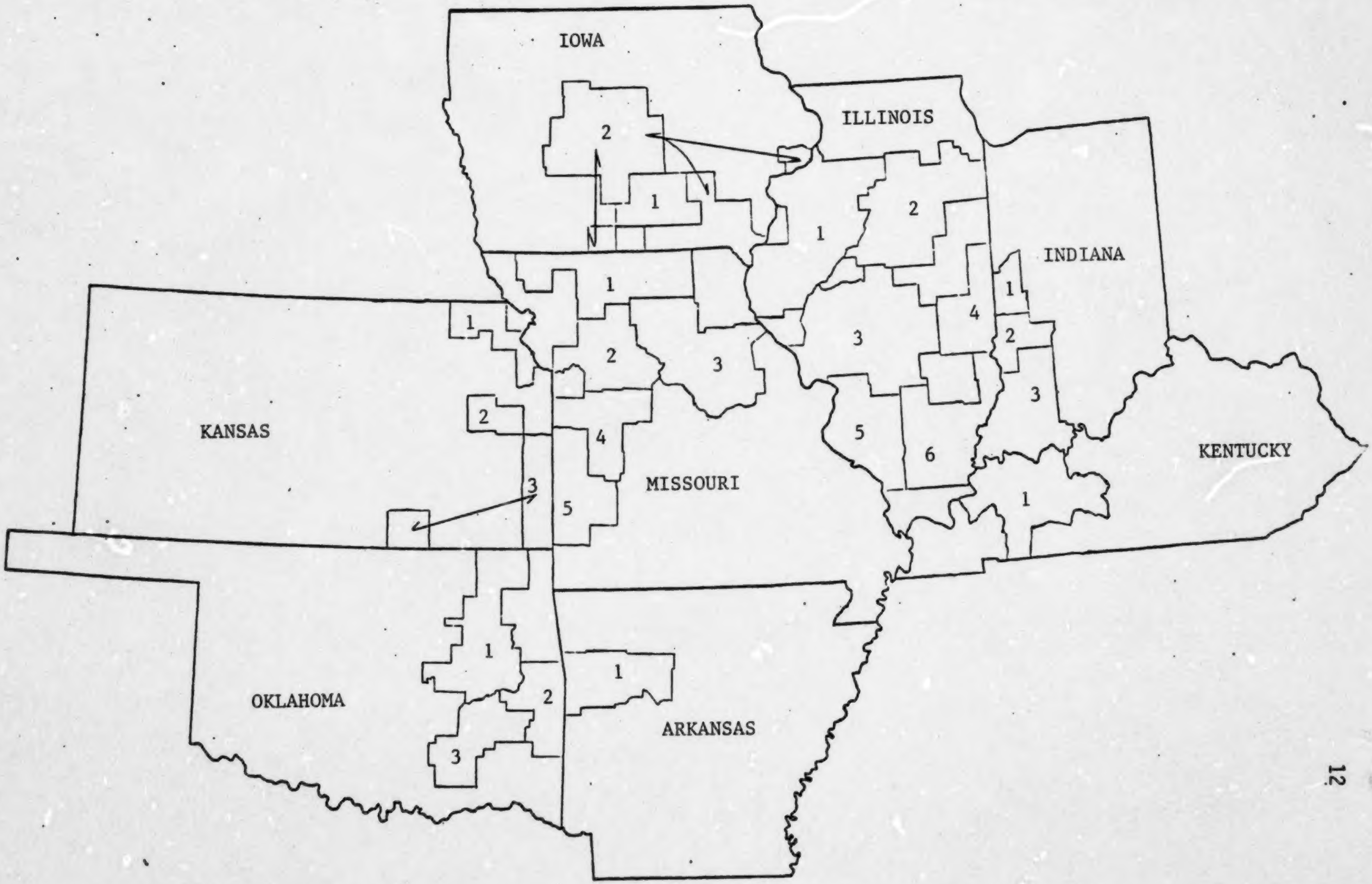

MONTANA
1
2
3
4
5
NORTH DAKOTA
1
2
3
SOUTH DAKOTA
1
WYOMING
1
2
3
3
4
UTAH
3
1
2
COLORADO
1
2
4
3
7
6
5
ARIZONA
1
NEW MEXICO
1
2
3
4

Figure 3--Coal producing areas in the Western States.

Figure 4--Coal producing areas in the Interior region.


IOWA
2
1
ILLINOIS
2
1
INDIANA
1
2
3
4
3
5
6
1
1
2
3
KENTUCKY
1
2
4
3
5
KANSAS
MISSOURI
1
2
1
OKLAHOMA
3
ARKANSAS

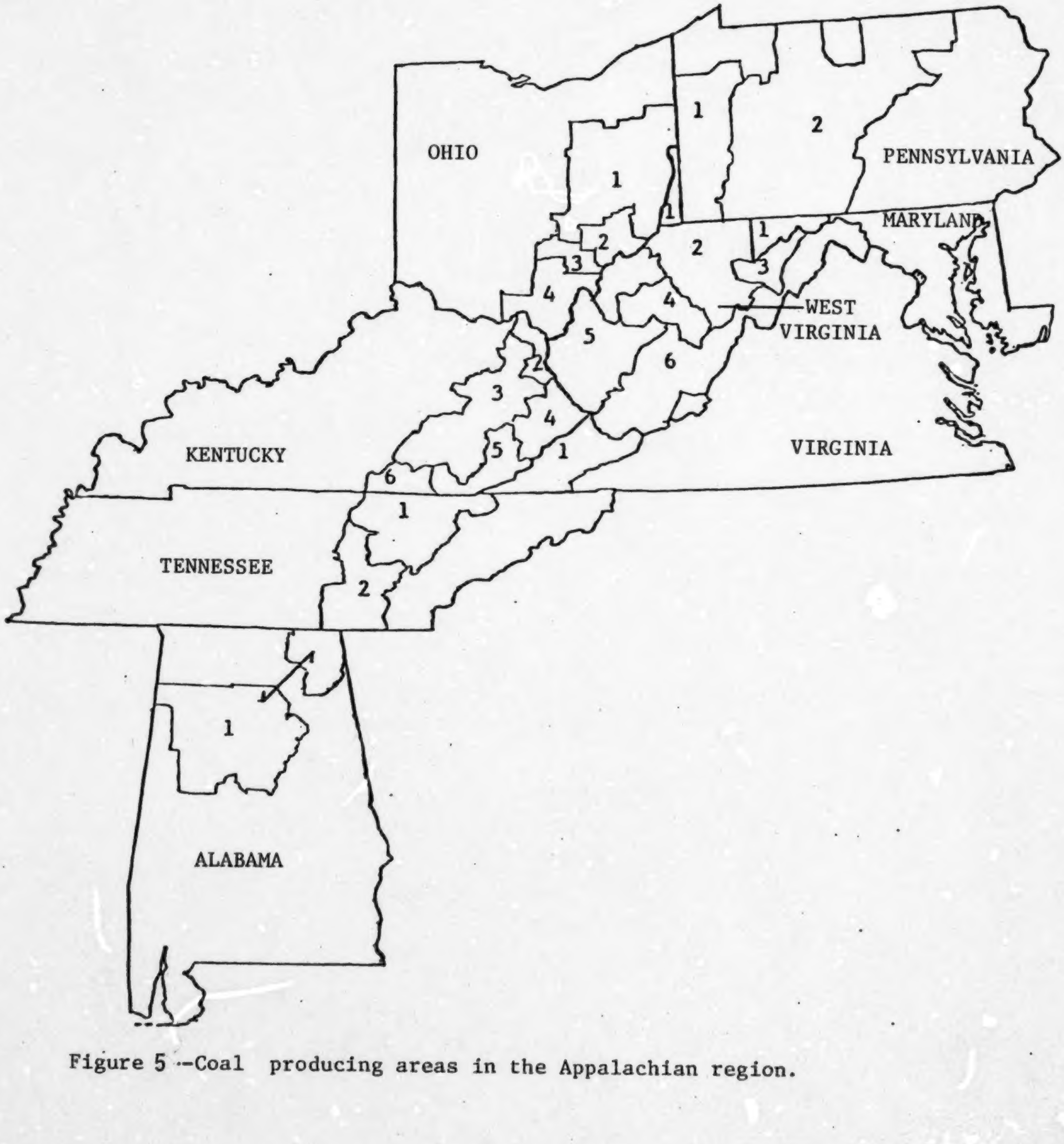

OHIO
PENNSYLVANIA
MARYLAND
WEST VIRGINIA
VIRGINIA
KENTUCKY
TENNESSEE
ALABAMA
1
2
3
4
5
6

Figure 5 --Coal producing areas in the Appalachian region.

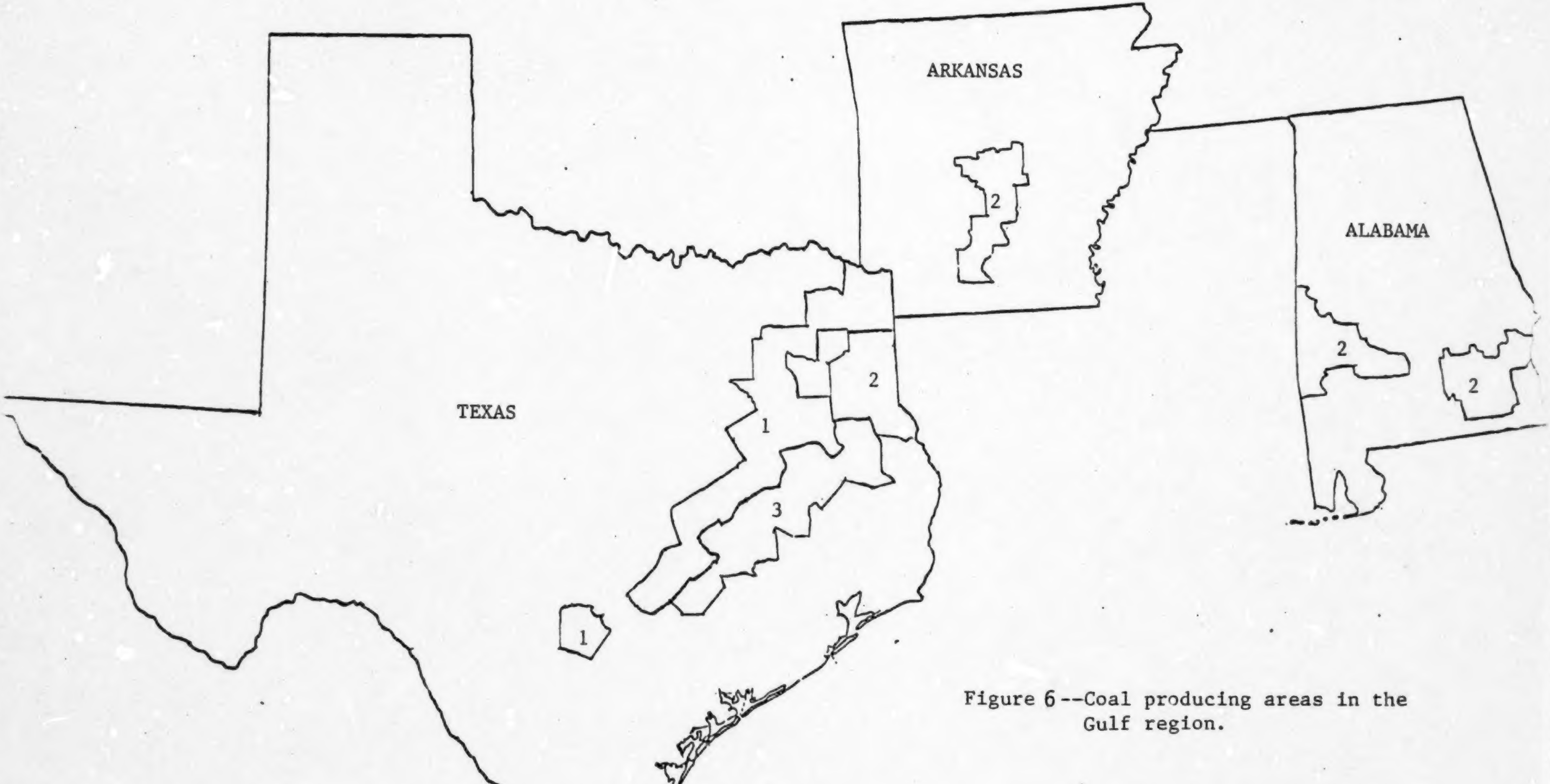

ARKANSAS
2
ALABAMA
2
2
TEXAS
1
2
3
1

Figure 6 --Coal producing areas in the Gulf region.

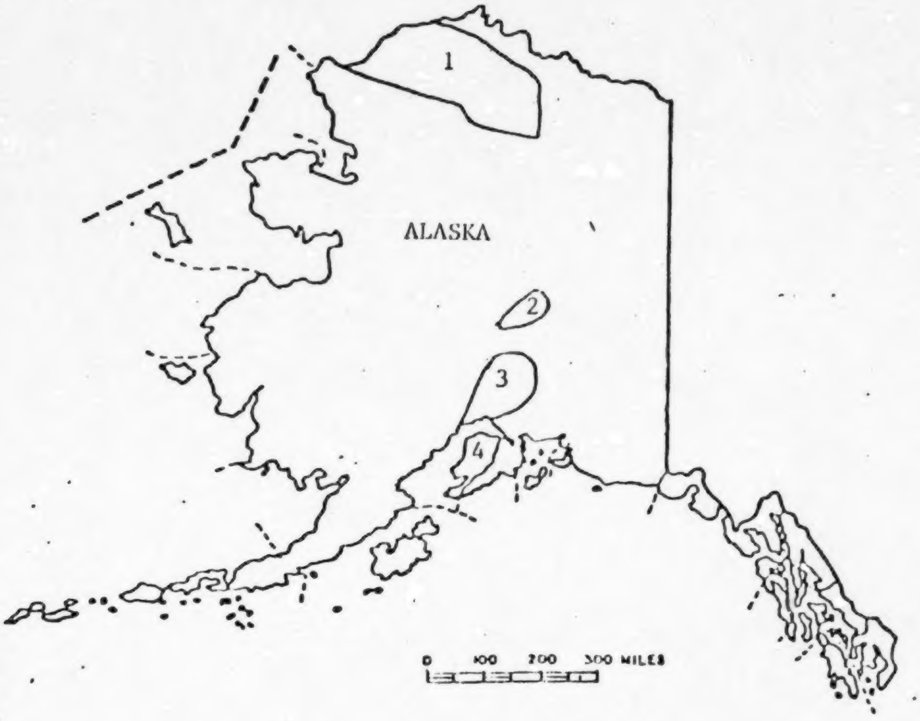
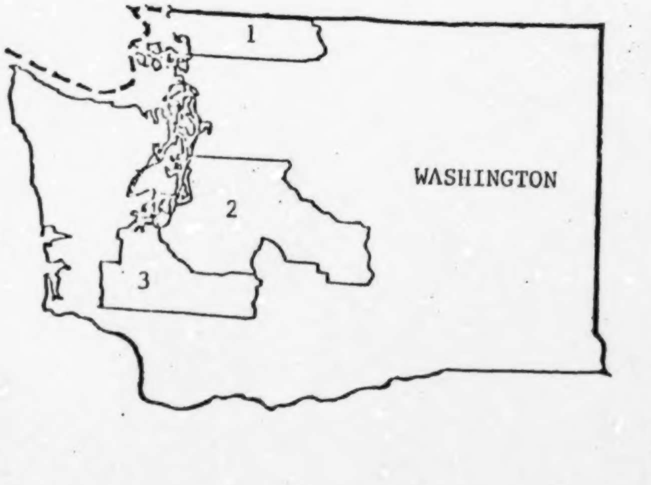

1
ALASKA
2
3
4
0 100 200 300 MILES

Figure 7--Coal producing areas in the Pacific region.


1
WASHINGTON
2
3
50 0 50 100 150 200 250 300 MILES

A. Yes. Optimization is somewhat of a misnomer. We did not optimize and do not presently consider our model to be an optimization model. It is currently an accounting model and useful only for short-run analysis. We do not speculate about or attempt to site unannounced new generating capacity.

Q. Jerry Eyster. How do you treat industry oversupply or more capacity than demand?

A. That issue is a difficult one given that we are examining only one year at this time (1975). We have plans to extend the analysis for each year up to the present time. This would give us more information about operating characteristics for each plant and the stability of their suppliers. Another facet of Jerry's question is industrial coal boilers. We have developed a research proposal to analyze industrial coal boiler suppliers over time and are pursuing funding for that project.

Q. Rich Bernknopf. Did you determine selling prices for coal from each CPA?

A. We are using aggregate selling prices as reported in COAL WEEK but intend to do a detailed analysis of supply prices over time.

Q. Rich Bernknopf. Are prices FOB the point of sale?

A. Yes.

Q. Larry Mack. Eventually you will have to optimize your model. Are you going to have the flexibility to minimize alternative areas such as transportation, capital, and other kinds of costs?

A. We have already received some pressure to optimize. Our transportation element is a free-standing model. Dr. Ebeling at North Dakota State University can perform various optimization strategies with it. That gives us the flexibility to do many things, including siting of power plants or determining new, optimal mixes of suppliers. We could also utilize our demand model to determine electricity demand for the intermediate term and then optimize the siting of power plants and their suppliers. We currently have no definitive plans for these types of analyses.

Q. Charles Macal. Do I understand correctly that you are going to use FOB cost of production and transport to indicate the validity of the model? What about component prices due to economic rent that are not considered in this type of framework? I can envision a situation where the delivered costs are lower than actual costs when contracts are signed due to economic rents.

A. I'm not sure what you mean. We are trying to simulate the real world with our model. We want to ignore the economic theory of price levels and try to reflect announced and existing selling prices. If economic rents are reflected in real world prices we would not identify them as such. We will not force rents into or out of prices to reflect different situations.

Q. Charles Macal. So the price is as reported for coal coming from a particular region?

A. Yes, and eventually as coming from a particular mine.

Q. Charles Macal. So any rents would already be included?

A. Hopefully, yes.

Q. Jerry Eyster. Where are the prices coming from for each region?

A. There is no one source. We look at COAL WEEK, Keystone, and historical prices or Form 423 and subtract transportation costs.

Q. Jerry Eyster. So there is no theory that anticipates pricing?

A. That's right. It's a descriptive accounting or simulation model.

Q. Jerry Eyster. So you could test where current market shipments are, in fact, optimal given costs of production, transportation, and utilization? You could analyze how close current market flows are to a minimum cost solution.

A. Yes

Q. Rich Bernknopf. I had problems getting some utility companies, such as Duke Power, to supply origins and prices of their coal. Were you able to get this information, especially for wholly owned mines?

A. We had the same problem.

Q. Rich Bernknopf. What did you do in those instances?

A. We made educated guesses.

As mentioned earlier, the definition of the CPAs was the responsibility of Virgil Whetzel. Any questions concerning them should be directed to him. In the linear programming or accounting model we will use these CPAs but monitor the mine source of each power plant's coal supply.

Table 2 describes the structure of the supply rows and activities in our accounting model framework. Our objective function minimizes the cost of producing electricity but the dollar amount obtained is of little interest, at least initially. We are primarily interested in tracking the coal from the CPAs so that we can evaluate the impacts resulting from coal-related developments. The supply activities use the selling price of the coal as the cost coefficient. Underground and strip mining are separated.

The selling price of the coal in the mining activities does not reflect the costs of reclamation and taxes. These costs are subtracted from the selling price and entered as costs in reclamation and taxation activities for each CPA. We do this so that we can analyze scenarios dealing specifically with differences in reclamation and taxation costs. Reclamation cost estimates were made for the western States by Kenneth Leathers and for the other CPAs by Virgil Whetzel. Taxes paid in each CPA are determined by the Economic Development Division using mine tax models. The level of detail in the mine tax models varies, with very good detail in the western states and less detail in the Interior, Appalachian, Gulf, and Pacific models.

The supply activities monitor the depletion of reserves and there is an upper limit on the coal which can be mined in each CPA. Underground mining is assumed to be 50 percent efficient and strip mining 90 percent efficient in removing coal from the ground. The mining activities accumulate production both in tons and Btu and there is an upper limit on production in each CPA based on established mining capacity. The supply rows then transfer the coal to transportation or preparation activities. These transfer activities are monitored in tons and Btu and are unconstrained.

TABLE 2. SUPPLY ROWS AND ACTIVITIES --FOR EACH CPA

	Mining		Reclamation		Taxes	
	Underground	Strip	Underground	Strip	Underground	Strip
	Selling price minus cost of reclamation and taxes		Estimates by Leather and Whetzel		EDD Level of detail varies	
	000 tons		per acre		000 tons	
Reserves	X	X				
Million tons						
Accumulative depletion	50%	90%				
Upper limit						
Production	X	X	X	X	X	X
000 tons						
Million Btu's			Land disturbance Accounting		Accumulative Taxes Paid	
Upper limit						
Transfer						
To transportation or	X	X				
To preparation						
Million Btu's						
Unconstrained						

Working on definitions of reserves and production by sulfur and Btu content

We are currently working on the definition of reserves and production in each county by sulfur and Btu content. This involves an update to the Bureau of Mines 1974 analysis defining eleven categories of sulfur for each county in the United States. We feel this will be necessary to perform a valid analysis of the 70 percent versus 90 percent scrubbing alternatives defined by EPA regulations. It is our ultimate objective to be able to determine the exact seams from which coal is removed for each power plant. Then, by knowing the sulfur and other characteristics of that coal, we can provide a definitive analysis of the markets which that coal can enter.

In the supply rows and activities we also accumulate the total land disturbance for reclamation and the total taxes paid.

Coal Preparation

The coal preparation portion of the model is under development by Norman Dalsted at Colorado State University (Table 3). He is working closely with DOE, Keystone, and Mine Safety and Health Administration data files to produce an accurate inventory of preparation plants and to define the mines which supply each plant. Where appropriate, we move coal from each mine through the preparation plant and change the characteristics of the coal for shipment to the power plant. We determine a cost for preparing each unit of coal. Each preparation plant will have an upper limit of capacity. The coal is then transferred from the preparation plant activity to transportation activities using transfer rows. The raw material uses of the preparation plant are also accumulated, including its water use. We monitor the water and solid waste pollution created by the preparation plant. We also deal with the land required for the disposal of the solid wastes. We have not yet constructed this section of the model.

TABLE 3--COAL PREPARATION (CLEANING)

UNDER DEVELOPMENT - NORM DALSTED

	1	2	3	4
COST-OPERATING $/MMBTU	X	X	X	X
CAPACITY 000 TONS UPPER LIMIT	X	X	X	X
TRANSFER FROM MINING TO TRANSPORTATION TONNAGE CHANGE BTU CHANGE SULFUR CONTENT CHANGE	X	X	X	X
WATER CONSUMPTIVE USE POLLUTION ADDED	X	X	X	X
SOLID WASTES AMOUNT GENERATED LAND REQUIREMENT	X	X	X	X

Q. Lowell Smith. How complete would you characterize your file of existing coal preparation plants? Have you identified the majority of them or are you still working on them?

A. We are still working on them but the work is nearing completion. We have combined and compared DOE, MSHA, Keystone, and EPRI files to form a composite list.

Q. Lowell Smith. I was going beyond a simple listing of plants. Have you looked into the operating characteristics of each preparation plant?

A. No. We have reviewed the literature concerning the different types that exist but have not tied that to the list. We intend to do that when Norman Dalsted finishes his analysis of power plant water use. Is there substantial interest in the operating characteristics of each plant?

C. Lowell Smith. That's a higher order question. If you are performing policy analysis to determine if an existing plant could tighten up on sulfur emissions through increased use of prepared coal, then how much more equipment is it reasonable to install to lower sulfur emissions. These are interesting policy questions but I think it is basic, first of all, to determine what is going in and what kind of residuals and end products are coming out.

C. Andy Van Horn. Most coal preparation plants are designed primarily to remove ash rather than sulfur. In our current work for EPA we have performed comparisons of input and output streams and, in most cases, it appears to be uneconomic to upgrade existing coal preparation plants that were designed primarily for washing to remove sulfur. We are currently examining how far coal preparation can go in meeting standards for removal of ash particulates.

C. Voice. I would say that utilities will begin to think seriously about coal preparation.

A. It appears from the data that they already are. We think we can contribute to the analysis by completely inventorying the preparation plants, identifying their sources of coal, and the destination of the cleaned coal.

C. Voice. There are many institutional questions that are associated with coal preparation plants, for example, whether a sale would be attractive to a group of utilities. The differing nature of coal can make a coal preparation plant very unique.

Q. Voice. What percentage of coal is processed through preparation plants?

A. Voice. Historically it's been quite large--somewhere around 80 percent.

C. Lowell Smith. One must be careful about historical numbers because utilities tend to clean underground coal and not surface coal and the mix between these is changing.

Q. Jerry Eyster. How many preparation plants did you find?

A. About 900 I think.

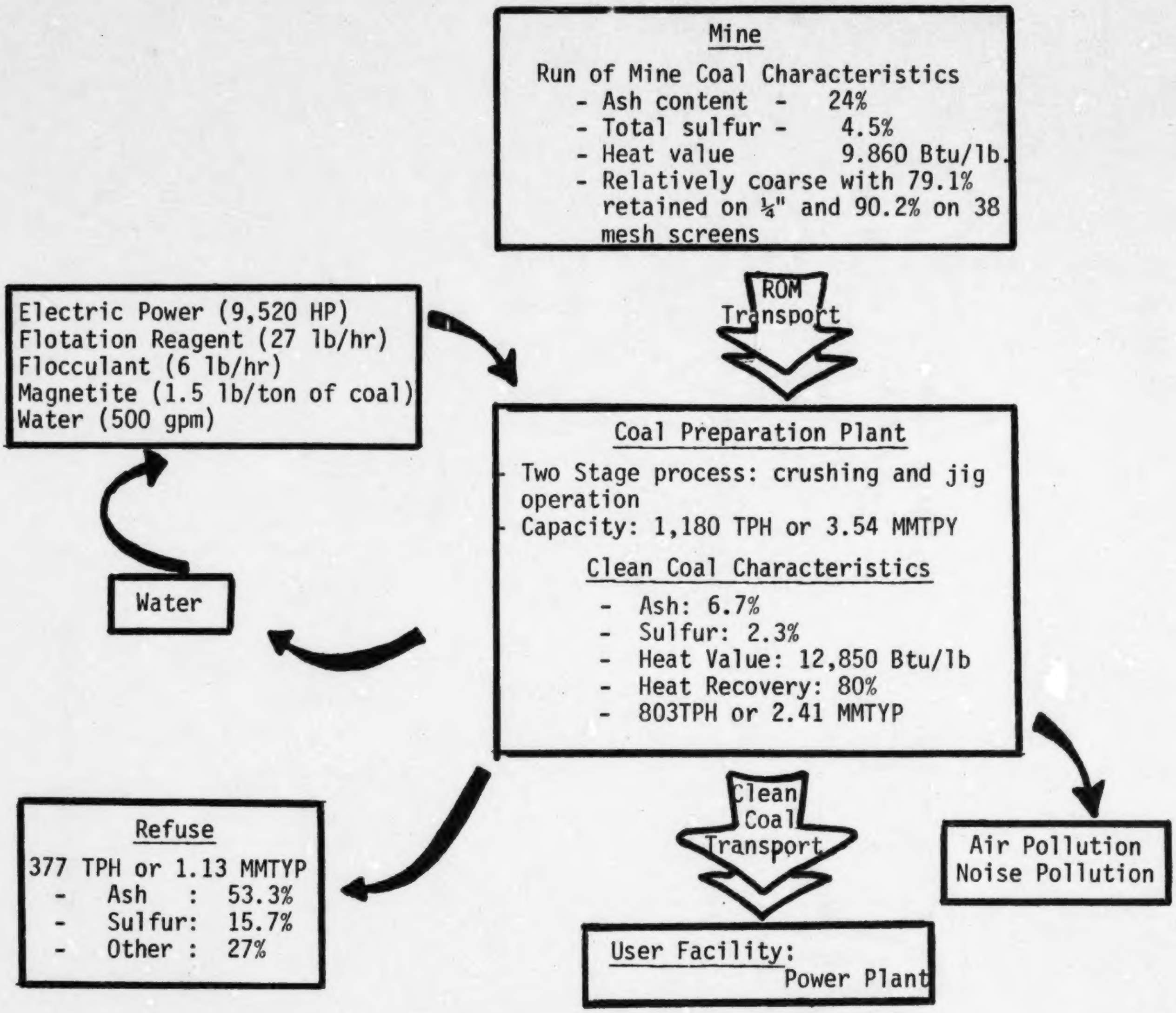
Figure 8 is an example coal preparation plant. The plant receives its coal from a midwest coal mine and the coal has average characteristics as defined in the figure. The coal is usually transported to the plant via truck or conveyor. This example has a two stage process using crushing and jig operations. Its capacity is 1,180 tons per hour or 3.54 million tons per year. The characteristics of the processed coal are shown. The ash and sulfur contents are reduced significantly. The heat value of the coal is increased significantly. The preparation plant uses electrical power, flotation reagent, flocculant, magnetite, and water as raw materials. It recycles most of the water it uses. It produces 53.3 percent ash refuse, 15.7 percent sulfur refuse, and 27 percent other types of refuse. The plant then loads the processed coal on a transportation facility for shipment to the power plant.

Transportation

Our transportation model was developed under contract by Ken Ebeling at North Dakota State University. The model will move an annual tonnage of coal from a mine or preparation plant to a power plant. It moves that coal over the most efficient route, monitoring capacity on each link. The information necessary to run the model is an origin, a destination, and the annual tonnage to be transported. We have determined the approximate

Figure 8

Midwest Coal Mine


Mine
Run of Mine Coal Characteristics
- Ash content - 24%
- Total sulfur - 4.5%
- Heat value 9.860 Btu/lb.
- Relatively coarse with 79.1% retained on ¼" and 90.2% on 38 mesh screens
ROM Transport
Electric Power (9,520 HP)
Flotation Reagent (27 lb/hr)
Flocculant (6 lb/hr)
Magnetite (1.5 lb/ton of coal)
Water (500 gpm)
Water
Coal Preparation Plant
- Two Stage process: crushing and jig operation
- Capacity: 1,180 TPH or 3.54 MMTPY
Clean Coal Characteristics
- Ash: 6.7%
- Sulfur: 2.3%
- Heat Value: 12,850 Btu/lb
- Heat Recovery: 80%
- 803TPH or 2.41 MMTYP
Refuse
377 TPH or 1.13 MMTYP
- Ash : 53.3%
- Sulfur: 15.7%
- Other : 27%
Clean Coal Transport
User Facility: Power Plant
Air Pollution
Noise Pollution

Four Types of Equipment Commonly Used

1.) Comminution: rotary breakers, double and single roll crushers
2.) Classification: vibrating screens
3.) Separation: jigs, heavy medium vessels
4.) Dewatering: vibrating screens

capacity for each link and if the capacity for any link is reached, the model can reroute the coal or build additional capacity. The model provides a cost for the movement and can provide future costs depending on the year specified. If capacity is to be added to an individual link that cost is included in the cost for the coal movement.

Table 4 defines the transportation activity in our accounting model. The cost provided by the transportation model is in the objective function. The transportation activities accept coal from transfer rows and use transfer rows to deliver it to the power plant. The transfer rows are unconstrained. We assume that the transportation activities are 99 percent efficient. We can transport the coal by rail and/or barge. We can monitor the capacity of individual links. If there is a mode change there is a cost included for it.

The engineering transportation model can optimize (determine the one most efficient movement) or suboptimize (determine a small number of efficient alternatives). We specified this type of development to enable the ICAM to include the most efficient two or three alternative routings. Obviously this is irrelevant for those origin-destination pairs which have been established via contract. We force contract movements into the ICAM.

Q. Lowell Smith. How does your transportation model handle truck transport in the Appalachian area or truck transportation where it is important to coal transportation?

A. We do not model truck transportation.

Q. Lowell Smith. Do you have any plans to extend into that area?

A. No.

Q. Ed Hillsman. Where are you getting your information on link capacities?

TABLE 4--TRANSPORTATION

FROM EACH SUPPLIER (BY CPA) TO EACH POWER PLANT
KEN EBELING - NORTH DAKOTA STATE UNIVERSITY

COST $/MMBTU	
TRANSFER FROM MINE OR FROM PREPARATION PLANT TO POWER PLANT UNCONSTRAINED MMBTU	99% EFFICIENT
CAPACITY 000 TONS BY RAIL AND/OR BARGE LINK	
MODE CHANGE RAIL TO BARGE COST INCLUDED	

NDSU can optimize (one most efficient movement) or suboptimize (small number of most efficient alternatives)

A. As researchers who work in this area know, that is a weakness in the available data. We have reduced the 20,000 link FRA network to the 7,000 or 8,000 links we need to move coal. The capacity of each link is closely guarded information for most railroad companies. We basically use the capacity classes reported by the Government. The analysis in this area has to be rather crude until more accurate information can be developed.

Q. Lowell Smith. I have been told by rail transport experts that by looking at the ratio of siding length to the total length of track you can extend the analysis. So you can fairly accurately estimate the capacity of a link by looking at structural features.

A. That's what has been done to formulate the capacity classes we are using. Our engineering model also considers signaling, condition and age of track and ties, grade, speed, turns, and other features.

Q. Verne Loose. For short-run, analysis track features shouldn't be too much of a problem because you know how much coal was moved in 1975 so if no diversions or substantial increases occur the capacity should be adequate.

A. But for a 1985 analysis the movement of coal over some links will quadruple. There are serious doubts whether the main lines in North Dakota and Nebraska can handle that.

Q. Jerry Eyster. What about other commodities and seasonal use?

A. Intercommodity competition has occurred to us and we have developed a research proposal to investigate those issues. It was submitted to USDA but there was no interest in funding it. It now appears that ICC is interested in investigating these issues.

Q. Rich Bernknopf. It is my understanding that North Dakota State finds an efficient route between a known source and a known destination and then you put that information in your accounting model and account for that coal movement on the links that the route represents.

A. No. Ebeling keeps track of the capacity on individual links. In the accounting model we have an activity which describes an origin, a destination, a price, and the volume of each movement. Ebeling tracks the capacity of individual links and identifies capacity bottlenecks.

Q. Rich Bernknopf. So it is a two-stage process where Ebeling identifies a source, destination, and route for each shipment and then later accounts for that movement by adding it to the overall accounting model.

A. Except that his software is designed so that it's all one operation.

Q. Rich Bernknopf. The DOE has also accounted for rail and other modes of transport for coal and other commodities. Does Ebeling calculate rail rates and, if so, how?

A. Yes. It's an engineering cost formulation, not rates. We have compared his costs with actual rates for 1975 and the average error is in the 10 percent range.

Q. Jerry Eyster. So you assume that the railroads fully recover costs, that they use some procedure to allocate capital, and that they recover their variable costs. Your comparisons assume reasonableness in ICC rate setting and you can be at the high or low end, that the range is great and where you are in that range depends on competing modes of transportation.

A. We attribute a cost of return to capital in a detailed formulation. Yes, our estimates can be anywhere within a wide range.

Q. Jerry Eyster. And you can explain 90 percent of the variance?

A. Yes.

C. Voice. That's an interesting conclusion. Does that apply to shipments crossing the Great Plains because there's an element of monopoly in those movements? Some analyses have shown that those railroads take advantage of that monopoly element.

A. Which would suggest those rates are in the upper end of the range.

Q. Voice. Does that still fit with cost estimates?

A. Yes. Our analysis does not substantiate the monopoly conclusions. Our analysis suggests the railroads are not abusing any monopolies they might enjoy.

Q. Jerry Eyster. What rates were examined for comparison?

A. 1975.

Q. Jerry Eyster. The market in 1975 was just developing.

A. The 1975 analysis would probably hold for 1976 and 1977 but we estimate that it changed in 1978. Ebeling is doing some 1978 analyses under contract to EPRI and we are looking forward to seeing those results.

Figure 9 is an example of a computer map generated by the transportation model. The thickness of each line defines the annual capacity being moved over that line. The links are traced by numbering the nodes

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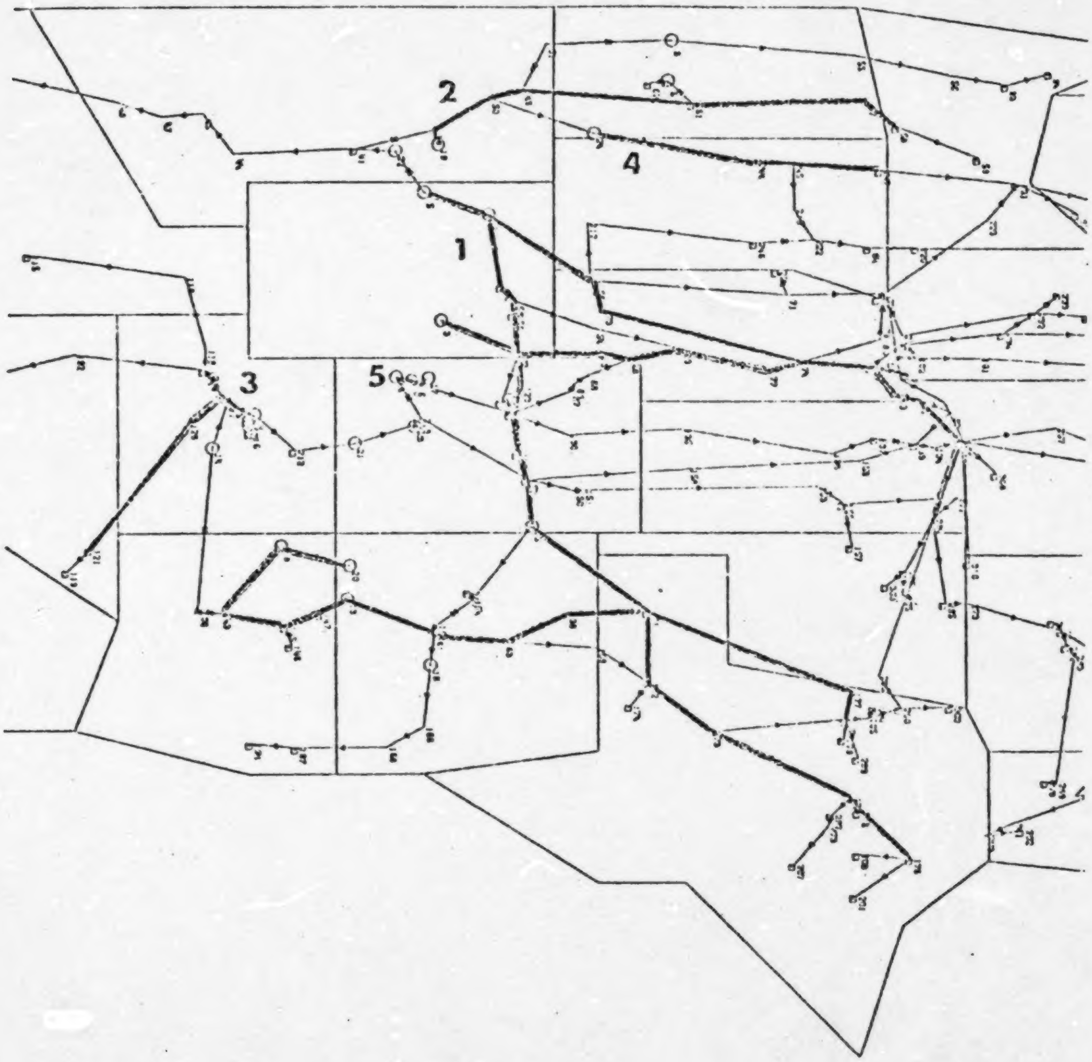
Figure 9
BASE CASE RAILROAD LINK WITH 10 MILLION
TONS OF COAL PER YEAR OR MORE



which connect them. This figure was generated for the Western States ICAM. The thickest lines originate in the Colstrip and Gillette CPAs and go east and south. There are also substantial movements originating in Arizona and New Mexico going to Texas.

Figure 10 shows the system routines used by the transportation model. There is a mine data set and a power plant data set which are supplied primarily by me. The rail file and barge file were obtained from the Federal Railway Administration and the Corps of Engineers. These rail and barge files are simplified using search and network simplification routines. The number of links in the coal transportation model is less than one-half the links in the original file. The transportation model is initiated using request cards and can use several optimization routines. The output includes routings, volume, current cost, and projected cost.

Q. Voice. Does the transportation model represent a topographic description of the railroad lines, examine speeds, and try to determine time and fuel requirements?

A. Yes.

Table 5 is an example of the computer output from the transportation model. The labeled example is the operating characteristics and investments for coal moving from CPA C004 to power plant 3104. The one way mileage is 1,285 and the heat content of the coal being transported is 11,657 Btu per pound. It takes 142.88 hours to make a round trip to and from this power plant and, given the annual tonnage, it requires 2.4 100-car unit trains to supply this power plant. The annual tonnage of coal moved to this power plant is 1,250,000. The model calculates the

Figure 10

TRANSPORTATION SYSTEM ROUTINES

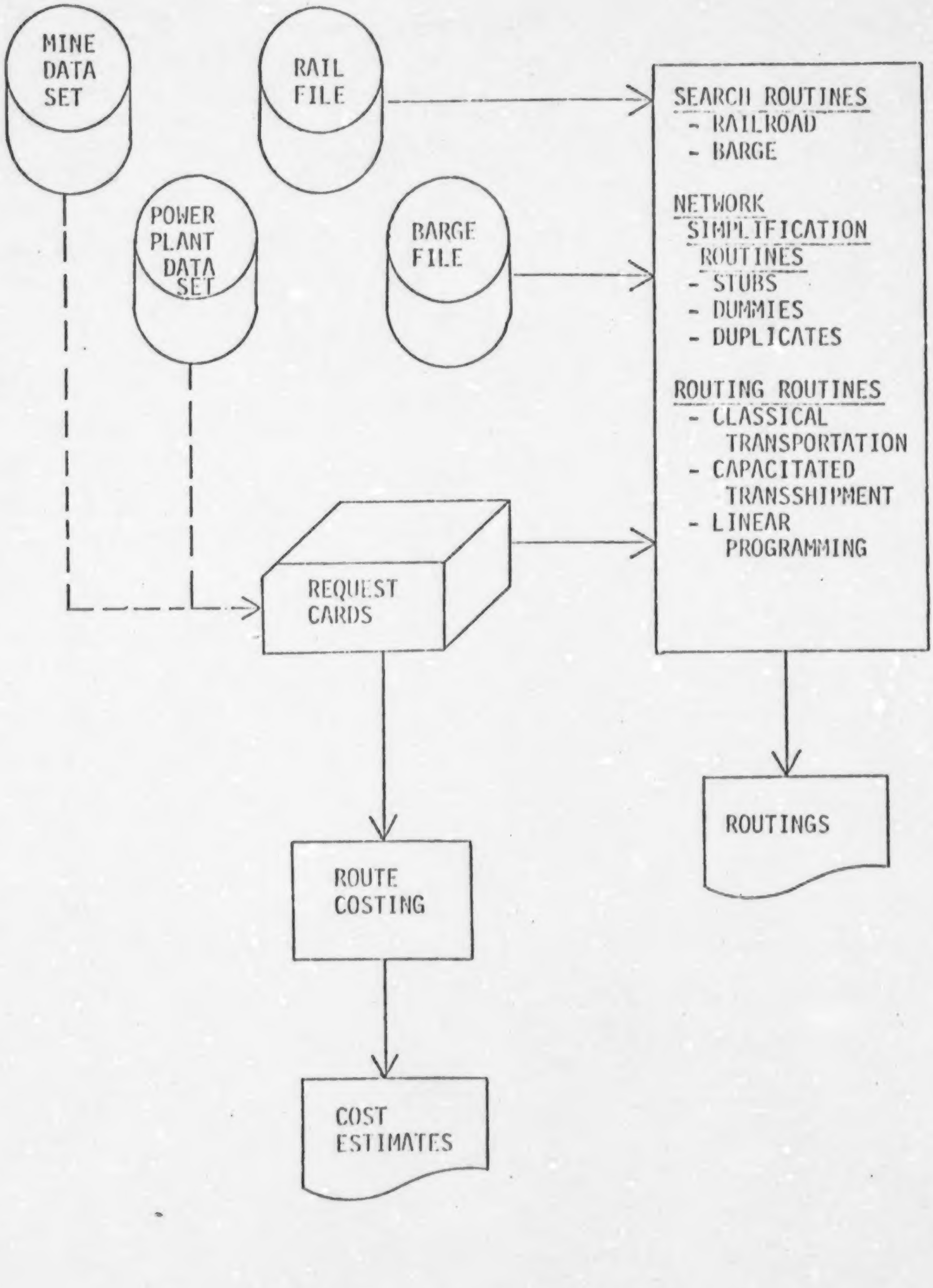

MINE DATA SET
RAIL FILE
POWER PLANT DATA SET
BARGE FILE
SEARCH ROUTINES
- RAILROAD
- BARGE
NETWORK SIMPLIFICATION ROUTINES
- STUBS
- DUMMIES
- DUPLICATES
ROUTING ROUTINES
- CLASSICAL TRANSPORTATION
- CAPACITATED TRANSSHIPMENT
- LINEAR PROGRAMMING
REQUEST CARDS
ROUTINGS
ROUTE COSTING
COST ESTIMATES

Table 5. Example computer output of engineering transportation model.

```
 OPER.CHAR.&INVESTS  FOR COAL FROM C004 TO 3045
CNE-WAY-MILES=1220.       BTU=11657.
TIME =      136.78     NET TONS=  1300000.     RST-INV=        8771747.
TRAIN=        2.39     GRS TONS=  2979000.     TRK-INV=        6129999.
                                               TOT-INV=       14901746.
ANNUAL OPER.= 10909555.     COST PER TON =     11.5269
    CC043045  COST        0.494420E 00
    CC043045  COST        0.885011E 00

                                   ↗ CFA      ↗ power plant

 OPER.CHAR.&INVESTS  FOR COAL FROM C004 TO 3104
ONE-WAY-MILES=1285.       BTU=11657. per lb.
TIME =      142.68     NET TONS=  1250000.(coal) RST-INV=      8810588.
TRAIN=        2.40     GRS TONS=  2865000.     TRK-INV=        6177884.
                                (coal + train)  TOT-INV=       14988472.
ANNUAL OPER.= 10994776.     COST PER TON =     12.0779 $
    C0043104  COST        0.518052E 00 75 }
    CC043104  COST        0.927312E 00 85 } $/MMBTUs


 OPER.CHAR.&INVESTS  FOR COAL FROM CC04 TO 4057
ONE-WAY-MILES=1588.       BTU=11657.
TIME =      174.21     NET TONS=   970000.     RST-INV=        8336337.
TRAIN=        2.27     GRS TONS=  2223240.     TRK-INV=        5924461.
                                               TOT-INV=       14260798.
ANNUAL OPER.= 10543760.     COST PER TON =     14.9076
    C0044057  COST        0.639426E 00
    C0044057  COST        0.114457E 01


 OPER.CHAR.&INVESTS  FOR COAL FROM C007 TO 9016
ONE-WAY-MILES=  20.       BTU=11609.
TIME =       12.69     NET TONS=   112000.     RST-INV=          70106.
TRAIN=        0.02     GRS TONS=   256704.     TRK-INV=          11200.
                                               TOT-INV=          81306.
ANNUAL OPER.=    19933.     COST PER TON =      0.3533
    CC079016  COST        0.152179E-01
    CC079016  COST        0.272399E-01


 OPER.CHAR.&INVESTS  FOR COAL FROM C007 TO 9019
ONE-WAY-MILES=  13.       BTU=11609.
TIME =       11.34     NET TONS=    31000.     RST-INV=          17348.
TRAIN=        0.00     GRS TONS=    71052.     TRK-INV=           1550.
                                               TOT-INV=          18898.
ANNUAL OPER.=     2739.     COST PER TON =      0.3174
    CC079019  COST        0.136594E-01
    C0079019  COST        0.244682E-01


 OPER.CHAR.&INVESTS  FOR COAL FROM MT02 TO 9045
ONE-WAY-MILES=   0.       BTU= 6500.
TIME =       10.00     NET TONS=  2900000.     RST-INV=        1430604.
TRAIN=        [illegible]     GRS TONS=  [illegible]     TRK-INV=              0.
```

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rolling stock investment, the track investment, and a total investment. It calculates an annual operating cost for this movement of $12.08 per ton. The cost per million Btu for this movement in 1975 was $0.52 and is projected to be $0.93 in 1985.

We have used historical transportation cost data to verify the output of the engineering cost model. In 1975, the engineering cost model produced cost estimates which averaged within 10 percent of the actual cost as provided by the railroads to the Interstate Commerce Commission. We feel that these cost estimates will be even more accurate in the future since the railroads seem to be pricing unit train, large volume movements more in relation to the cost of the movements.

Power Plant Conversion

There is an activity in the ICAM for each power plant (Table 6). There were approximately 300 in 1975. There are approximately 450 coal-fired power plants, 100 megawatts or greater, expected to be operating by 1985. Each power plant has an operating cost defined in dollars per million kilowatt hours of output. This operating cost was obtained from the 1975 Steam Electric Plant Construction Cost and Annual Production Expenses bulletin published by the Energy Information Administration, Department of Energy.

Each power plant accepts coal, defined in million Btu, from a transfer row. Each power plant has its own conversion ratio defined in million Btu inputed per million kilowatt hours of electricity outputed. This conversion ratio is defined using historical information published by the Federal Energy Regulatory Commission. Eventually, an analysis of historical reliability statistics will be performed for each power plant.

TABLE 6--POWER PLANT CONVERSION

FOR EACH POWER PLANT SITE - 300 IN 1975

COST-OPERATING
- $/MMKWH

TRANSFER
- FROM TRANSPORTATION (MMBTU)
- TO UTILITY DEMAND (MMKWH)

CONVERSION RATIO
- MMBTU/MMKWH
- RELIABILITY STATISTICS

CAPACITY
- MMKWH
- UPPER LIMIT

PRODUCTION
- MMKWH
- ACCOUNTING ROW

WATER
- WITHDRAWAL
- CONSUMPTIVE USE
- POLLUTION

POLLUTION
- AIR BY TYPE - SULFUR CONSTRAINTS
- SOLID WASTE

Before this can be accomplished, the reliability information published by the Edison Electric Institute must be corrected. This process is underway at the National Electric Reliability Council. The analysis of reliability statistics will provide us with information to project the reliability of individual power plants for any year.

Each power plant generates electricity. There is an upper limit on the production of electricity for each power plant based upon its theoretical production capacity. This theoretical production capacity will be modified using the reliability characteristics as determined by the analysis described above. The output of each power plant is accumulated using an accounting row. The production of electricity in each utility service area is also accounted for using power plant ownership data.

The raw materials inputed and pollution outputs of interest are individually monitored for each power plant. Water withdrawal and consumptive use is measured and correlated with the type of cooling system in operation. Water pollution levels are determined depending upon the amount and characteristics of the coal burned and on the type of pollution control systems operational.

Air pollution loadings are maintained for each power plant as is the amount of solid waste materials produced. Again these are correlated with the complement of air pollution equipment installed at the plant.

Q. Rich Bernknopf. Do you have the capability to say exactly how much fly ash is being disposed of on site?

A. When we finish analyzing Form 67 data we can calculate how much fly ash is being produced but not where it is being disposed of.

C. Andy Van Horn. That can be done for a historical year but compliance with regulations may not be reflected in the historical data. Regulations are being developed and revised in each State and by the early 1980's plants not in compliance in 1975 will be in compliance and that will change the amount of solids produced. Pollution control costs can be as much as 40 percent of the cost of burning coal so that component is very important in the selection of a coal supply source for any individual power plant.

A. We intend to analyze those changes by examining historical equipment complements at each plant and comparing them statistically with the regulations in effect and the amount of waste produced. If a plant is not in compliance, we can assume an equipment complement to bring it into compliance and then examine the pollution produced by other plants with that equipment complement.

There are currently no plans for developing activities to reflect the capital costs of building new plants. The ICAM is primarily concerned with the simulation of the operating trajectories involved in the production of coal-fired electricity. It is feasible to expand the model to include the siting and construction of new power plants to meet the demand for coal-fired electricity.

Demand

We have a contract with John McKean at Colorado State University to develop an econometric residential electricity demand model. Demand within the ICAM can be handled in one of two ways (Table 7). We can use demand in the accounting sense, i.e., determine that there is no minimum demand that must be met and accumulate electrical output for each utility company. This would be the approach taken in a very constrained model where we would maximize demand rather than minimize cost. This approach assumes that each utility company can determine its own demand for electrical capacity and we merely monitor the coal-fired plants and their sources of supply. Each future plant is treated as necessary based on the utility company's own projections of capacity. The plant is fitted into a national system and the levels of coal production and electricity generation in each area determined. The other approach that could be taken is

TABLE 7--DEMAND

CAN HANDLE TWO WAYS

1. USE DEMAND IN ACCOUNTING SENSE, i.e.,
   ---NO MINIMUM DEMAND THAT MUST BE MET
   ---ACCUMULATE OUTPUT FOR EACH UTILITY COMPANY

2. USE ECONOMETRIC MODEL
   ---COMPUTE TOTAL ELECTRICITY DEMAND FOR EACH UTILITY COMPANY
   ---DETERMINE COAL POWERED PORTION FOR EACH UTILITY AND POWER PLANT
   ---FORCE LP TO MEET THAT DEMAND

FOR EACH UTILITY COMPANY

NO COST AT PRESENT

DEMAND

MAXIMIZE OUTPUT - NO LIMIT ON COST

or

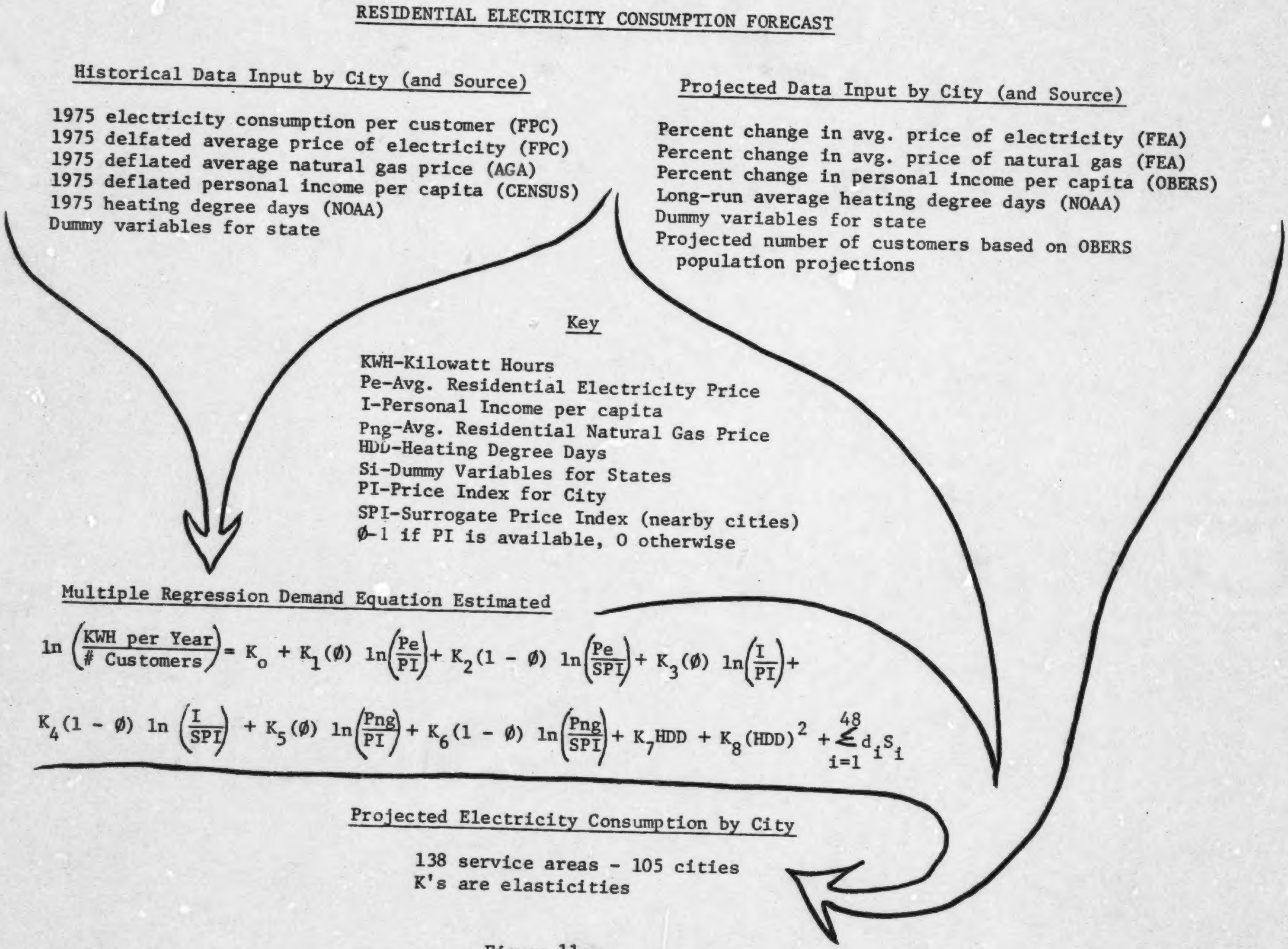
MINIMIZE COST - LOWER LIMIT ON DEMAND

to use the econometric demand model to compute the total electricity which will be demanded in each utility service area, then determine the coal-fired portion for each utility, and force the ICAM to meet that demand. This approach duplicates the analysis each utility performs in determining its future demand. New plants and supply patterns would be established by the ICAM to meet a minimum demand for coal-fired electricity. This is the approach used by most regional linear programming models.

It is our intent, at least initially, to follow the first approach. We will continue to pursue the development of econometric models to determine the demand for residential, commercial, and industrial electricity. Once these models are operational, we will consider using the second approach to meet the demand for electricity. The second approach would necessitate further development of the ICAM. This further development will probably be necessary to make the ICAM model more useful for intermediate and long-run analysis.

Therefore, at the present time there is an activity for each utility company. There is no electrical distribution cost. These distribution costs may be separated later. We force the model to maximize output within the severe constraints imposed on each power plant and its transportation and supply sources. Once the maximum output has been determined we may allow the model an increasing amount of flexibility in minimizing costs by placing lower limits on the demand for electricity.

Figure 11 describes the current residential electricity demand function developed by Dr. McKean. The multiple regression demand equation



RESIDENTIAL ELECTRICITY CONSUMPTION FORECAST

Historical Data Input by City (and Source)

1975 electricity consumption per customer (FPC)
1975 delfated average price of electricity (FPC)
1975 deflated average natural gas price (AGA)
1975 deflated personal income per capita (CENSUS)
1975 heating degree days (NOAA)
Dummy variables for state

Projected Data Input by City (and Source)

Percent change in avg. price of electricity (FEA)
Percent change in avg. price of natural gas (FEA)
Percent change in personal income per capita (OBERS)
Long-run average heating degree days (NOAA)
Dummy variables for state
Projected number of customers based on OBERS population projections

Key

KWH-Kilowatt Hours
Pe-Avg. Residential Electricity Price
I-Personal Income per capita
Png-Avg. Residential Natural Gas Price
HDD-Heating Degree Days
Si-Dummy Variables for States
PI-Price Index for City
SPI-Surrogate Price Index (nearby cities)
Ø-1 if PI is available, 0 otherwise

Multiple Regression Demand Equation Estimated

$$\ln\left(\frac{\text{KWH per Year}}{\#\text{ Customers}}\right) = K_o + K_1(\emptyset)\ \ln\left(\frac{Pe}{PI}\right) + K_2(1-\emptyset)\ \ln\left(\frac{Pe}{SPI}\right) + K_3(\emptyset)\ \ln\left(\frac{I}{PI}\right) +$$

$$K_4(1-\emptyset)\ \ln\left(\frac{I}{SPI}\right) + K_5(\emptyset)\ \ln\left(\frac{Png}{PI}\right) + K_6(1-\emptyset)\ \ln\left(\frac{Png}{SPI}\right) + K_7 HDD + K_8(HDD)^2 + \sum_{i=1}^{48} d_i S_i$$

Projected Electricity Consumption by City

138 service areas - 105 cities
K's are elasticities

Figure 11

was estimated using historical input data by city including 1975 electricity consumption per customer, 1975 deflated personal income per capita, 1975 heating degree days, and dummy variables for each state. This multiple regression demand equation says that kilowatt hours per year per customer is a function of the average residential electricity price divided by the personal income per capita, the average residential electricity price divided by a cost of living index for each city, total personal income per capita divided by a price index for each city, the average residential natural gas price divided by a price index for each city, and the number of heating degree days for that utility service area.

Q. James Wade. Are the demand estimates for each power plant?

A. The econometric estimates are for utility service areas which may involve several power plants.

Q. James Wade. Do you monitor data necessary to use this econometric model in terms of economic conditions relevant to that area?

A. Yes, using data from various sources such as American Gas Association, FERC, EIA-DOE, EPRI, OBE-Commerce, etc.

Q. Jerry Eyster. How do you handle long distance transmission of power or intercompany transfers and do you have a dispatch model to determine how much of the demand should be coal-fired?

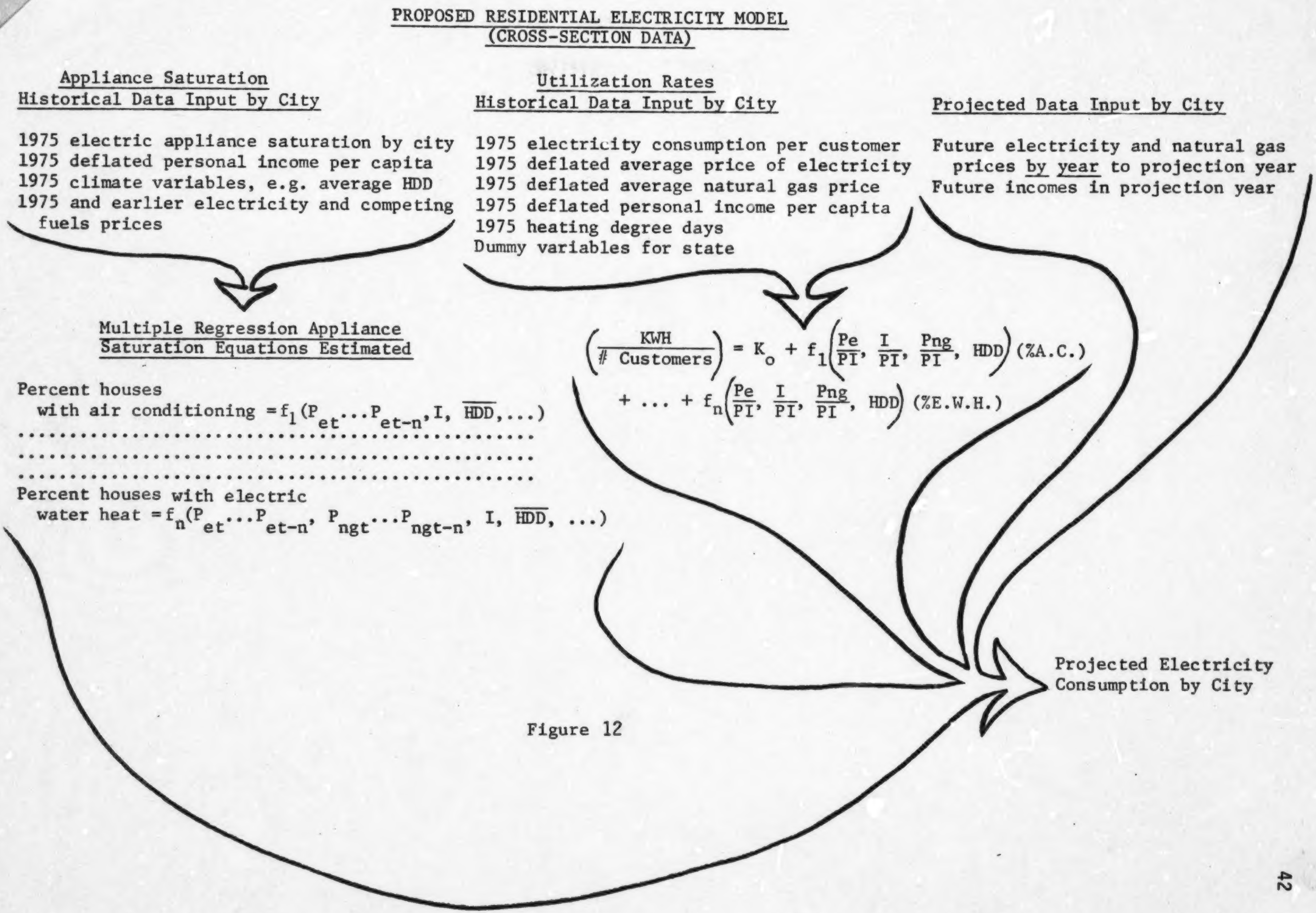
A. We do not consider long distance transmission except through the ownership percentages in plants by different utilities. There is no analysis of sales and resales. We do not have a dispatch model but assume that coal-fired power is base load. We analyze historical plant capacity factors and make projections of those factors.

The projected electricity consumption by city is developed for 138 electric utility service areas. These projections were developed using 105 standard metropolitan statistical area (SMSA) cities. The projected data by city includes the percent change in the average price of electricity, the percent change in the average price of natural gas, the percent change in personal income per capita, the long run average heating degree days, dummy variables for each state, and the projected number of customers determined using OBERS population projections.

Q. Verne Loose. You treat only residential demand? What about industrial and commercial demand?

A. To date we have treated only residential demand. Industrial demand is part of a proposal we are trying to get funded. We haven't actually used demand estimates in the simulation model except to assume there will be demand for electricity outputed by announced power plants. We would like to expand our demand work not so much for use in our short-run model but rather to prepare for any intermediate and long-run analyses. We feel our model is more detailed than others now available and therefore more useful for utility service area projections.

The econometric demand equation is similar to the best of other studies. Our analysis does use cost-of-living indexes for each city and performs the analysis by SMSA. This is a more detailed level of disaggregation than the state or regional studies used in other models. We intend, if funding permits, to expand our residential electricity demand analysis to include both time series and cross section data. Figure 12 describes some of the ideas we have for the expansion of this analysis. The expansion involves an appliance saturation equation in combination with the utilization equation described in Figure 11. With this approach we would determine dynamic appliance saturation levels which is the first determinant of the demand for electricity, that is, the higher the percentage of households using the various kinds of appliances, the higher the demand for electricity.



PROPOSED RESIDENTIAL ELECTRICITY MODEL
(CROSS-SECTION DATA)

Appliance Saturation
Historical Data Input by City

1975 electric appliance saturation by city
1975 deflated personal income per capita
1975 climate variables, e.g. average HDD
1975 and earlier electricity and competing fuels prices

Utilization Rates
Historical Data Input by City

1975 electricity consumption per customer
1975 deflated average price of electricity
1975 deflated average natural gas price
1975 deflated personal income per capita
1975 heating degree days
Dummy variables for state

Projected Data Input by City

Future electricity and natural gas prices by year to projection year
Future incomes in projection year

Multiple Regression Appliance
Saturation Equations Estimated

Percent houses with air conditioning $= f_1(P_{et} \ldots P_{et-n}, I, \overline{HDD}, \ldots)$

....

....

....

Percent houses with electric water heat $= f_n(P_{et} \ldots P_{et-n}, P_{ngt} \ldots P_{ngt-n}, I, \overline{HDD}, \ldots)$

$$\left(\frac{KWH}{\#\ Customers}\right) = K_o + f_1\left(\frac{Pe}{PI}, \frac{I}{PI}, \frac{Png}{PI}, HDD\right)(\%A.C.)$$

$$+ \ldots + f_n\left(\frac{Pe}{PI}, \frac{I}{PI}, \frac{Png}{PI}, HDD\right)(\%E.W.H.)$$

Projected Electricity
Consumption by City

Figure 12

However, the fact that a household has a particular appliance does not determine the amount of time which that appliance is used. The rate of utilization is the second major variable which must be considered. The rate of utilization is the analysis which we have already performed. The proposed scheme is to dynamically determine the number of appliances owned by households and then determine the amount of time each appliance is used. This pair of multiple regression equations (perhaps more than two) would be used to project electricity consumption by city and utility service area.

Western States Report

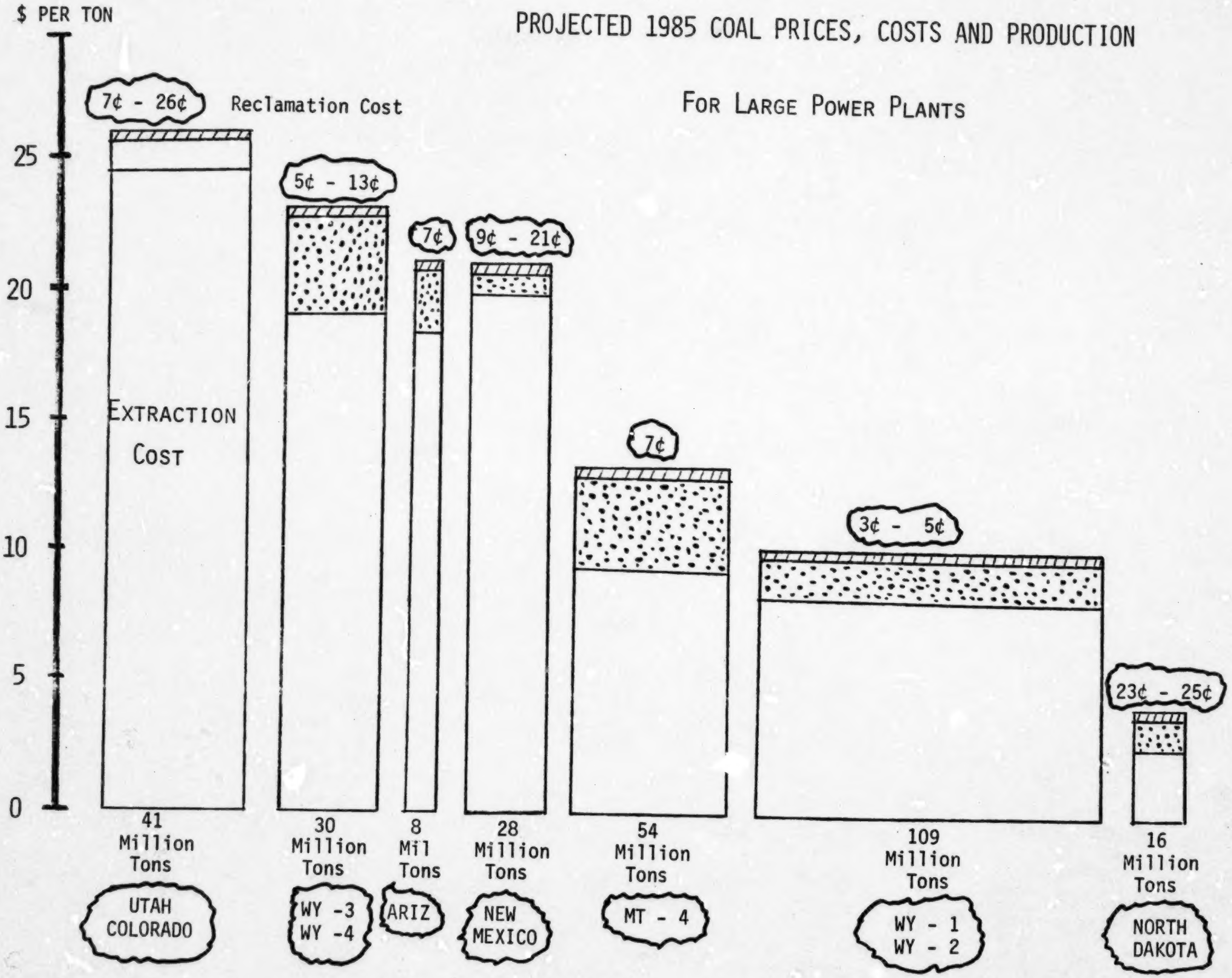
Our original scheme for the development of a national model was to develop data and models for each coal-producing region. The sequence was to be the Northern Great Plains, the Rocky Mountain States, the Interior, the Appalachia, the Gulf, and the Pacific coal-producing regions. This proved to be an inefficient approach. Therefore, we decided to develop western states data and use it to build and debug the framework for the model. This was accomplished and a report written. We are now working to complete the data acquisition and organization necessary for the national model. A western states model is operational and has been used to do simple, preliminary scenario analysis.

Figure 13 describes projected 1985 coal price and production levels for the western states model. The greatest portion of the selling price per ton is the extraction cost. However, the portion of the selling price going for taxes varies widely between CPAs in the western states. The reclamation cost does not vary as widely and is a very small part of the selling price per ton. A similar graph for Interior and Appalachian CPAs will probably exhibit a much narrower range of taxation costs and a wider

Figure 13

PROJECTED 1985 COAL PRICES, COSTS AND PRODUCTION

FOR LARGE POWER PLANTS



range of reclamation costs. The width of each bar defines the amount of coal sold from each of the areas described at the bottom of the bar.

Q. Voice. How were the extraction costs projected?

A. By escalating 1978 selling prices by 6 percent per year. This is very crude. Our coal supply pricing methodology needs considerable improvement.

Figure 14 shows projected western coal production and remaining reserves at the beginning of the 1985 analysis year. The left vertical scale describes the cumulative production in each CPA listed at the bottom of the figure measured in million tons. The right vertical scale measures the reserves remaining in 1985 in billions of tons, that is, the right scale is 100 times the left scale. Cumulative production in the 1976-1984 period will be highest in WY02 (Gillette). The second highest will be MT04 (Colstrip). These two areas, in addition to MT05, will have the greatest amount of reserves remaining. Even though the most production will occur in those two CPAs, the reserves remaining will still be very large. The North Dakota CPAs will have exhausted 40-50 percent of their total reserves by 1985. The C001 CPA will have exhausted more than one-half of their known reserves. It must be remembered, however, that these reserve estimates may change.

The only scenarios analyzed using the western states model were selected construction delay alternatives. It was assumed that any power plant scheduled for 1982 or later would not be in operation by 1985. Figure 15 shows the 1975 coal production in the western states at 65 million tons. The outer solid circle defines the 286 million tons projected to be mined if no construction delays occur. If a three year

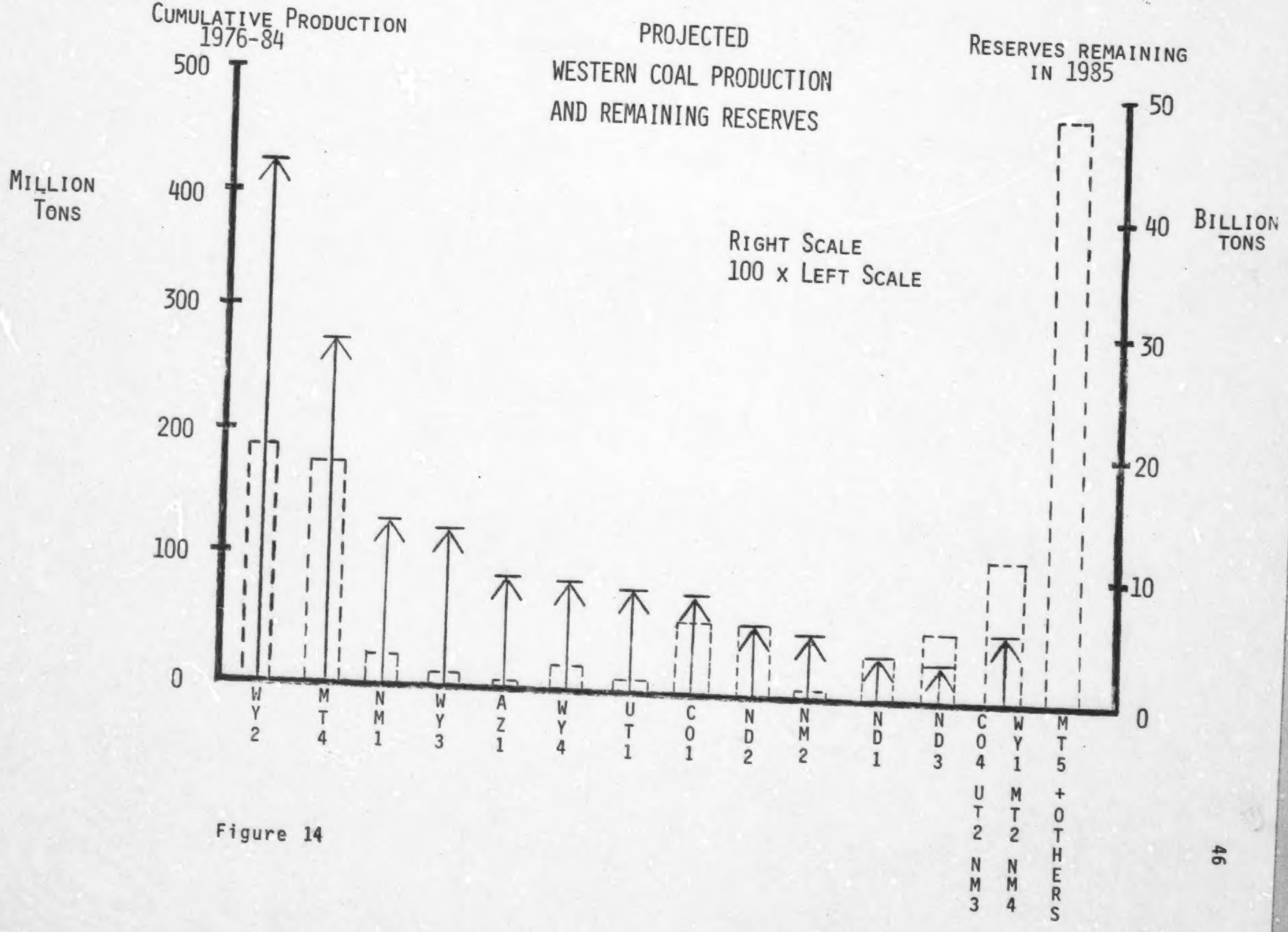
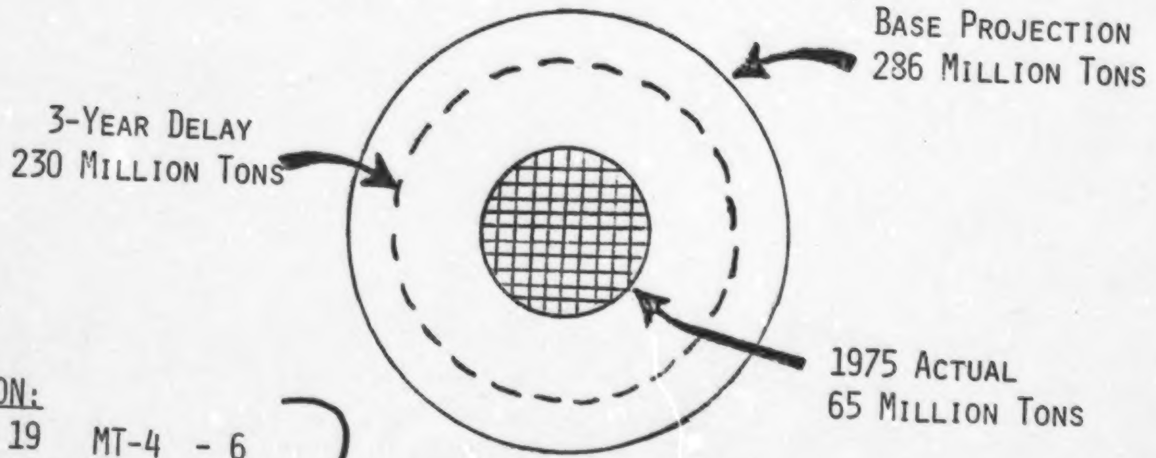

CUMULATIVE PRODUCTION
1976-84
MILLION
TONS
500
400
300
200
100
0
PROJECTED
WESTERN COAL PRODUCTION
AND REMAINING RESERVES
RESERVES REMAINING
IN 1985
BILLION
TONS
50
40
30
20
10
0
RIGHT SCALE
100 x LEFT SCALE
WY2
MT4
NM1
WY3
AZ1
WY4
UT1
CO1
ND2
NM2
ND1
ND3
CO4 UT2 NM3
WY1 MT2 NM4
MT5 + OTHERS

Figure 14

FIGURE 15

SELECTED ALTERNATIVE SCENARIO
FOR 1985
3-YEAR CONSTRUCTION DELAY
IN POWER PLANTS TO USE WESTERN COAL


BASE PROJECTION
286 MILLION TONS
3-YEAR DELAY
230 MILLION TONS
1975 ACTUAL
65 MILLION TONS

IMPACTS ON:

WY-2	- 19	MT-4	- 6
NM-1	- 9	ND-2	- 4
UT-2	- 8	CO-1	4
UT-1	- 6		

MILLION TONS
DEDUCTED FROM 1985 BASE PROJECTION

construction delay occurs, then the 1985 production will be 230 million tons of coal from the western states. The greatest impacts will be felt in CPA WY02, where production will be decreased by 19 million tons. Other CPAs show lesser amounts of reduction. Some CPAs in the western states are unaffected by a three year construction delay.

Summary

It has been our objective to build a very microscale data base and simulation model describing the use of coal by large generating plants in 1975. We feel we are well on our way to successfully accomplishing that objective. We also keep current year-by-year scenario tables describing new coal-fired generating capacity. The combination of an accurate simulation model and current scenario tables permits us to perform accurate short-run analyses.

We would like to improve our model in several ways. The data base first needs to be updated year by year through 1979. We need to include power plants under 100 megawatts and their suppliers from 1975 through 1979. We need to build an industrial coal-use data base at a comparable level of detail to our utility data base. And finally, we need to modify the simulation model, to make it more like a linear programming model, to perform more flexible short-run analyses and provide the capability for performing intermediate and long-run analyses.

Q. Verne Loose. Since the simulation model treats only announced plans for plants, your demand model is really an adjunct analysis; it doesn't reflect the number of power plants built and operated?

A. That's right!

Q. Jerry Eyster. This is a tremendous data base you have developed. Do you have an estimate in terms of people or money it would take to maintain it? You now stand the risk of being often proven wrong because of the level of detail present in your data base.

A. We encourage people to prove us wrong because it improves our data base each time they do so. I have two graduate students working for me at Colorado State University. There are two other professionals working at North Dakota State University and the University of West Virginia. Our budget, before USDA overhead, is about $200,000 per year. Once the data base and software are operational, I think two graduate students could maintain it. At least two professionals would be needed for supervision and analysis.

Q. Larry Mack. Can you vary power plant sitings or be flexible about location of transmission lines?

A. We are not going to use our simulation model to perform those analyses but EPA wants us to coordinate with TEKNEKRON who can perform those types of analyses.

Q. Verne Loose. How specifically can you examine community impacts?

A. We know the specific sites for power plants and mines. Our model will project short-run levels of production. We then provide those outputs to Lloyd Bender's team in the Economic Development Division. They translate them into community impacts. That's the topic of our next workshop.

C. Lloyd Bender. We work at the county level with data dealing with individual mines.

Q. George Ferrell. What interest does USDA have in this area and what is your five year plan for this research?

A. We've tried to interest USDA in competition for rail resources between grain and coal and in the impacts on rural communities of increased train traffic. We've proposed further analysis of the demand for electricity by rural cooperatives. We've tried to interest USDA in research on the impact of power plant pollution on crop production and acid rainfall.

C. Lloyd Bender. Competition for water and other resources seems to be the big issue on the resource side. On the development side the big issues are changes in rural areas, pollution migration, and income. This project is a laboratory through which we can study changes in rural communities.

C. We are performing a detailed analysis of the demand for water by different cooling systems. We will develop water use coefficients for each type of system and apply those coefficients to future power plants, depending on the system the utility plans to install.

C. Verne Loose. The competition for water could markedly change the types of cooling systems installed.

A. True, but once a power plant announces the type they will install, it is not likely to change.

ANALYSIS OF COAL DEVELOPMENT ISSUES WITH THE ARGONNE COAL MARKET MODEL*

by

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INTRODUCTION

This paper describes the Argonne Coal Market (ACM) Model and its use in analyzing coal-related issues. The quadratic programming framework for combining supply and demand data in an interregional model is briefly described in the first section. Supply and demand data and algorithms used in estimating coal transport and environmental control cost data are presented in the second section. The last section contains a description of previous uses of the model. Information in this paper is based largely on Refs. 1 and 2.

MODEL FORMULATION

The coal allocation system is represented in the ACM Model as a network of supply and demand nodes and directed branches connecting pairs of supply and the demand nodes. Supply nodes consist of regions of the U.S. defined so that the coal within each has relatively homogeneous characteristics, and the regions are compact. Costs of resource extraction are associated with the supply nodes. Extraction costs are increasing functions of the cumulative quantity of resource extracted.

Demand nodes represent geographical centers of demand differentiated between utility and industrial uses because of different environmental regulations and transport costs faced by the two groups. Costs at demand nodes are for precombustion treatment of coal or post-combustion treatment of flue gases to meet emission regulations for sulfur dioxide. Environmental control costs are assumed to be constant with respect to the quantity of coal consumed. Although the demand for coal is price-sensitive, this facet is not considered explicitly. Instead, the Model is used to solve the coal allocation problem based on a "scenario" in which coal demand is determined independently and provided exogeneously to the

Model. An iterative approach is also possible to insure consistency between scenario assumptions and results of the ACM analysis.

Branch costs are for transport and are assumed to be constant with respect to the quantity of coal shipped. Transport costs are estimated for each of the pairs of supply and demand nodes.

The coal allocation problem is that of determining which supply nodes produce what quantities of coal such that all demand node requirements are satisfied. The ACM Model employs a quadratic programming formulation to solve the allocation problem. Mining, transportation, and sulfur removal costs are combined in the QP objective function. The objective function takes the form:

$$\text{Min} \sum_{i}^{S} \sum_{j}^{D} (K_i + t_{ij} + e_{ij}) X_{ij} \qquad (1)$$

where i is the index over S supply centers, j is the index over D demand centers, and

X_{ij} ≡ coal allocation over a period (Btu),

K_i ≡ market-type-dependent cost variable based on supply function (\$/Btu)

t_{ij} ≡ transport cost (\$/Btu), and

e_{ij} ≡ environmental control cost (\$/Btu).

A linearly increasing supply function can be defined for each supply area:

$$Z_i = a_i \left(\sum_{j}^{D} X_{ij}\right) + b_i \qquad (2)$$

where:

$\sum_{j}^{D} X_{ij}$ ≡ total coal production of supply area i,

a_i ≡ slope of supply function,

b_i ≡ intercept of supply function, and

Z_i ≡ production cost (\$/Btu).

Note, from Eq. 1 that all coal allocated from a supply region will be allocated at the same price. This implies that some producers will receive an economic rent equal to the difference between each producer's supply costs and the supply costs of the marginal producer in the respective area.

A supply function is shown in Fig. 1. The area under the function to be minimized for a competitive market would be:

$$K_i = b_i \sum_j^D X_{ij} + 1/2\ a_i \left(\sum_j^D X_{ij}\right)^2 \qquad (3)$$

The limited physical availability of coal provides one set of constraints in the model. Allocations to users must not exceed supply limits for each region and for each type of coal within that region. The totals of demands for coal from each demand area make up the other set of constraints. The constraint set is:

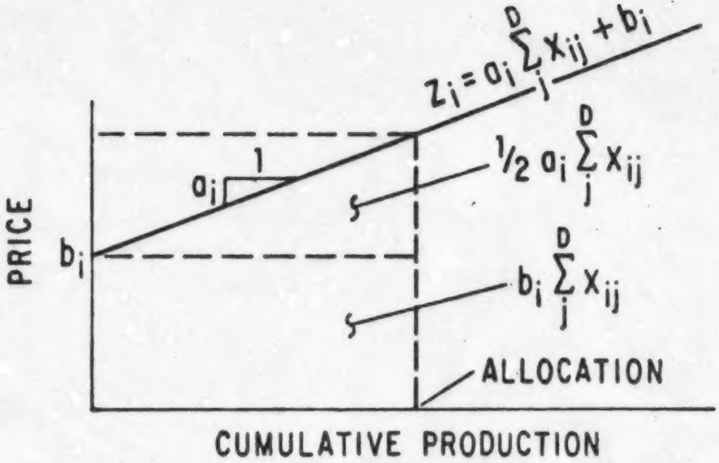
$$\text{Demand} \quad \sum_i^S X_{ij} = E_j \quad \text{for all demand areas} \qquad (4)$$

$$\text{Supply} \quad \sum_j^D X_{ij} \leq Q_i \quad \text{for all supply areas} \qquad (5)$$

where: E_j ≡ demand (Btu), and

Q_i ≡ upper limit of production cost function for supply area i.

Supply constraints are not necessary unless short-term production is constrained or long-term depletion of coal in supply region i is possible. Further discussions of the ACM Model can be found in Refs. 1-3. Representation of competitive and noncompetitive markets are discussed more thoroughly in Ref. 4.



$z_i = a_i \sum_j^D x_{ij} + b_i$
1
a_i
$\frac{1}{2} a_i \sum_j^D x_{ij}$
PRICE
b_i
$b_i \sum_j^D x_{ij}$
ALLOCATION
CUMULATIVE PRODUCTION

Fig. 1. Geometric Description of Market Representation in QP Objective Function

DATA AND ALGORITHMS

Coal Supply

The U.S. is disaggregated into regions for the purposes of the coal supply analysis. On the supply side the reasons for regional disaggregation are to make transportation charges more accurate and to differentiate among coals of different quality characteristics. The mining cost conditions that vary within a region are less important, since the regional market acts to equate all minemouth values for similar quality coal to the cost of the marginal producer within the area. The five major coal supply provinces of the U.S. are subdivided into nine supply regions, as shown in Fig. 2; the centroid of each region is the approximate production-weighted center of expected mining activity for the region. It is also a coal-loading point for rail shipment. The mining areas are defined on the basis of the significance and the similarity in characteristics of coal deposits. Certain coal deposits are excluded from these supply areas because they are of negligible importance in terms of production and because they would distort transportation costs. (5,6)

Q. Lowell Smith. Where do lignite coals fit in these categories?

A. All types of coal were considered in the definition of the coal supply curves.

Q. Voice. Subbituminous is considered with all the others?

A. Yes, the ICF supply categories were adjusted based on sulfur contents of lignite, bituminous, and subbituminous coals.

Q. Larry Leistritz. Then by putting it in terms of pounds of sulfur per million Btu, you normalized the difference in Btu contents between the three types of coals?

A. Right. We were looking at coals as vectors of characteristics such as heat content, sulfur, ash, etc. This type of geographical breakdown simply adds to the number of coal supply centers from which coal can be allocated. The breakdown in

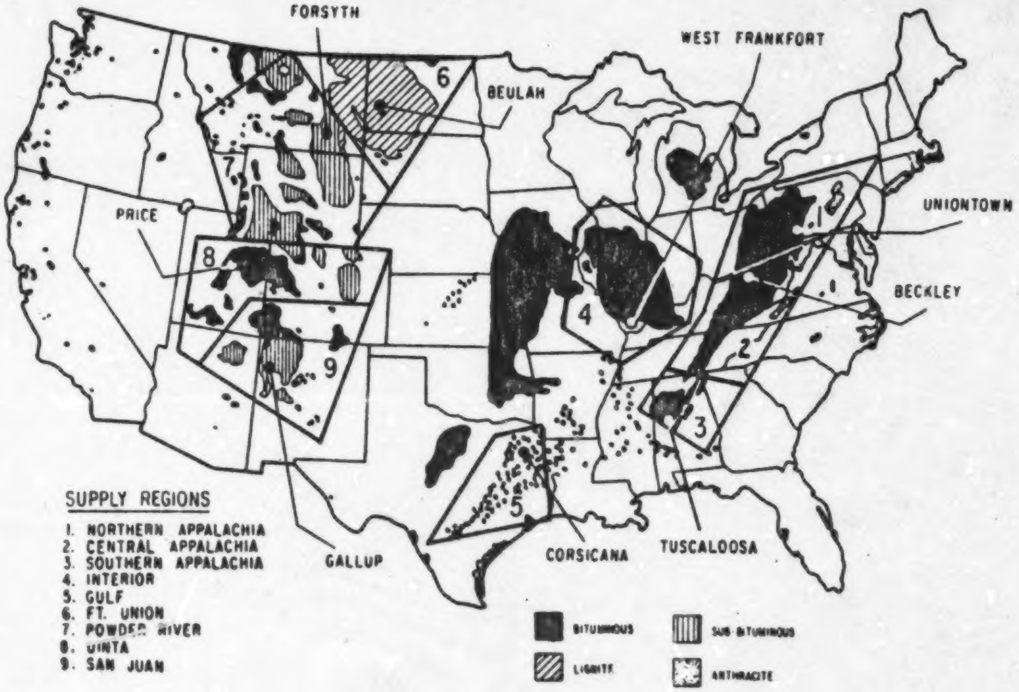

FORSYTH
WEST FRANKFORT
BEULAH
UNIONTOWN
PRICE
BECKLEY
GALLUP
CORSICANA
TUSCALOOSA
1
2
3
4
5
6
7
8
9
SUPPLY REGIONS
1. NORTHERN APPALACHIA
2. CENTRAL APPALACHIA
3. SOUTHERN APPALACHIA
4. INTERIOR
5. GULF
6. FT. UNION
7. POWDER RIVER
8. UINTA
9. SAN JUAN
BITUMINOUS
SUB-BITUMINOUS
LIGNITE
ANTHRACITE

Fig. 2. Coal Supply Areas

itself isn't important in terms of restricting the allocations. The allocations were made strictly on the basis of the vector quantities mentioned.

Q. John Green. Did you modify the ICF cost functions?

A. Yes, but we were really after a supply function. A cost function is one component of that.

Q. John Green. Have you done any comparisons with historical prices?

A. There was informal comparisons made for both prices and allocation patterns. Informally, there was agreement that they looked reasonable.

Q. Rich Church. Do you use one rail link for each of the 14 coal supply centers to get to the rail network?

A. We use the average cost of transporting coal from different points in the coal supply area to the supply center and add that to the cost of production. It's an average cost of access to each coal supply area.

Q. Rich Bernknopf. Are the supply curves marginal or average cost functions? Are they average costs of marginal mines or simply the marginal cost of mining in each region?

A. It is an incremental average cost for various mines in each supply region, i.e., the average cost of a marginal mine.

Q. Lloyd Bender. How sensitive is your model to location when computing transportation costs?

A. Sensitivity analyses were performed to determine the supply centers.

Q. Lloyd Bender. Would it pay to get better resolution by dividing regions into smaller areas?

A. In the construction of this model, cost effectiveness was considered in several respects. Sensitivity analysis and judgment were used to set the level of regional aggregation.

C. Larry Leistritz. The degree of detail which is important may differ depending on who you are responding to for policy analysis. The clientele for most of us in this region are governors, legislators, and State agencies who require greater disaggregation.

A. The point is well taken. I'm presenting a flexible structure which is not particularly data dependent.

C. Jerry Eyster. The level of aggregation may be influenced by whether you are looking at impacts, changes from some base, or forecasts of production levels. The centroid influences the magnitude of your numbers but using the same centroid in the base case and the sensitivity runs may result in the same general conclusion.

Since very little low sulfur coal lies between Appalachia and the Western supply areas, no low sulfur coal supply source is considered for the Midwestern portion of the United States. Instead, the Interior province is constructed to include the intermediate and high sulfur deposits of Illinois, Indiana, and western Kentucky. Although the Interior coal province does extend to include parts of Oklahoma, Kansas, Arkansas, and Texas (bituminous), these areas are of minor importance for out-of-state exports.

The Appalachian province is divided into northern, central, and southern regions to reduce the area (it is difficult to accurately specify one geographic centroid as a shipping point for a large area) and capture the distributions of coal quality types throughout the province. Northern Appalachia has less low sulfur coal than central Appalachia, although both provinces have high, intermediate, and low sulfur coal.(5) Southern Appalachia has predominantly higher sulfur coal, although significant deposits of low sulfur coal may potentially be mined in Alabama.

Supply areas are also defined for the Ft. Union lignite field (the Dakotas and eastern Montana) and southeast Texas. This lignite is not considered "compliance coal" since neither federal nor state sulfur dioxide standards can be attained without applying sulfur removal techniques with most of this coal. In fact, due to the relatively low Btu content of the coal and its low washability, stack gas scrubbing will be mandatory for all lignite used in these states.(6) Therefore, this lignite has been designated high sulfur coal.

The large land area of the Western coal fields and the wide varieties of coal available suggest three major subdivisions: Powder River, Uinta (Central Rockies), and San Juan (South Rockies). Powder River encompasses the primarily subbituminous coal deposits of Montana and Wyoming. Uinta refers to the bituminous reserves in northern Colorado and Utah while the San Juan area (including the Black Mesa) covers the primarily subbituminous and bituminous fields of Arizona and New Mexico. While these three supply areas do not strictly encompass all Western coal deposits, they account for the vast majority of mineable coal.(6) The quality characteristics of the coal in the supply areas are displayed in Table 1.

Although production costs play a key role in determining the market price of coal, the price received at a given mine is not always related to that mine's production costs. Many mines have unit costs that are lower than the prices they can obtain in the market. The mining costs that most accurately match the market price for coal are those of the marginal producers within each producing area. Linearly increasing functions are used to characterize the relationship between the marginal producer's costs and the volume of production. These relationships, which are long-run market supply functions, are based upon supply curves constructed by ICF, Inc. The slopes implied by the ICF step like functions have been employed where possible and adjustments to the intercepts have been made for transportation to the railhead, low sulfur premiums, and severance taxes.

ICF's supply functions are based upon engineering estimates of the costs of model mines in each producing area. The general procedure used by ICF to assign costs to various coal reserves begins with estimating and subtracting remaining reserves committed to existing mines from the demonstrated reserve base. Also excluded are the strippable reserves that

Table 1. Coal Reserves and Quality Characteristics by Major Mining Area

	Reserves (10^9 tons)[a]			
Supply Region, Coal Type	Total	Available for New Mines	Heat Content[b] (Btu/lb)	Sulfur Content[b] (% as received)
1. Northern Appalachia				
Low Sulfur[c]	0.609	0.244	11,528	0.73
Intermediate Sulfur[d]	13.367	10.002	11,528	1.38
High Sulfur	67.158	50.255	11,528	2.82
2. Central Appalachia				
Low Sulfur	5.556	3.370	11,937	0.80
Intermediate Sulfur[d]	7.071	6.511	11,937	1.05
High Sulfur	7.753	7.139	11,937	2.81
3. Southern Appalachia				
Intermediate Sulfur	1.534	1.273	11,850	1.0
4. Interior				
Intermediate Sulfur[d]	1.941	1.868	10,897	1.5
High Sulfur	86.332	83.080	10,897	3.05
5. Gulf				
Intermediate Sulfur	3.271	2.851	7,900	1.0
6. Ft. Union				
High Sulfur	20.844	20.691	6,776	1.4
7. Powder River				
Low Sulfur	118.161	115.573	8,723	0.52
8. Uinta				
Low Sulfur	4.562	4.134	11,107	0.66
9. San Juan				
Low Sulfur	2.851	2.481	10,000	0.69

[a] From ICF, Inc.,

[b] Based on coal deliveries reported in Coal Week, in 1977.

[c] Low sulfur coal, by definition, must comply with SO_2 emission limits of 1.2 lbs/10^6 Btu.

[d] Split out of ICF "High Sulfur" category on the basis of reserve portion that was relatively washable with conventional technologies.

[e] High sulfur coal, by definition cannot be treated by conventional coal washing techniques to meet a 1.2 lbs/10^6 Btu SO_2 limit. This coal must be scrubbed.

are illegal to mine. Next, uncommitted deep reserves are classified by seam thickness, mine depth, and mine size categories. Similarly, uncommitted strippable reserves are allocated according to mine size and overburden ratio groupings. These stocks of reserves are converted into production flows by assuming a mine life and a recoverability of reserve factor, and costs are computed for these flows.

Representative long-run supply curves are shown in Fig. 3 for low, intermediate, and high sulfur coal production in each supply area. ICF developed supply functions for three categories of coal: coal complying with current NSPS, all other steam coal, and metallurgical coal. These supply functions represent the prices per ton at the mine required to call forth various levels of new production capacity from the resource base.

Although the ICF cost data are quite detailed, they nevertheless aggregate marginal increments of production into large discrete blocks (up to 40 million tons each) coming into production at a higher price level. Depicting marginal cost increases within such a "step function" framework can misrepresent behavior if the steps are too large, i.e., larger than increments of production expected to come from opening the next new mine. Therefore, it was decided, for computational and theoretical reasons, to employ linear supply functions patterned after the slopes of segments of the ICF step functions. The ICF supply functions are divided into enough segments to assure that the linear approximation is reasonably true to the discrete steplike increases estimated by ICF.

One of the major adjustments to the ICF supply functions is the addition of severance taxes on coal production. These taxes are levied by coal-producing states and are subject to significant fluctuations as

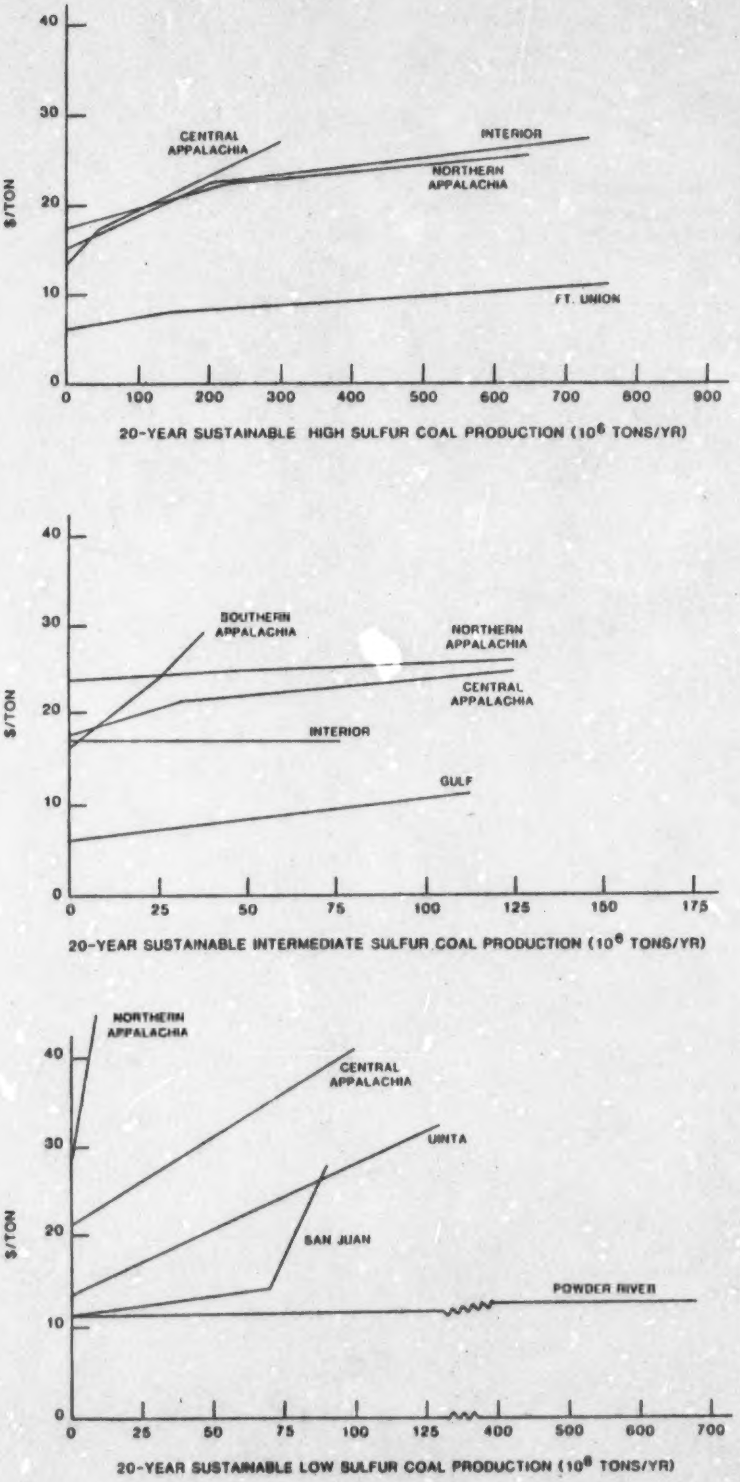


Fig. 3. Long-Run Coal Supply Functions

political conditions change. The estimates employed here are based upon personal communications with the FEA Office of Coal.

In projecting the costs of transporting the coal from the mine to the railhead, nominal distances have to be assigned from minemouth to loading point. Personal communications with coal company officials and examinations of existing rail lines suggest estimated distances of three miles in Appalachia and five miles in the Northern Great Plains and the Rocky Mountains. At 5¢/ton the total transport cost is 15¢/ton for Eastern coal and 25¢/ton for Western coal.*

These costs calculated above are for average quality coal extracted from the marginal mines in each area. Thus, they are equivalent to the average price of coal produced in each region. However, coal of low sulfur content has sold for considerably more than coal of higher sulfur content, particularly since the passage of the Clean Air Act.(8)

Even though utilities are known to place a considerable premium on low sulfur coal, efforts at quantifying the behavioral relationship between price and sulfur content have generally been unsuccessful. Therefore, a less formal procedure is employed in this study. Although the exact market premium offered for low sulfur coal is quite volatile, it should be related in a systematic way to the cost of sulfur control technologies. The premium for low sulfur coal should be no greater than the cost differential between low sulfur coal used directly and higher sulfur coal used with a control technology. This can be shown in the relationship:

$$T_L + P_L + S = T_H + P_H + C$$

T = transportation cost,

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*Transportation figures provided by sources at Peabody and Amax coal companies.

P = the marginal cost of production,

S = low sulfur premium,

C = the cost of the best available control technology, and

L,H = low and high sulfur coal.

This assumes that the two options are equally reliable and that utilities do not systematically prefer higher fuel costs over the higher capital costs of technologies. If the first two terms on each side of the above equality grow at approximately the same rate, and if the real cost of control technologies either declines or remains constant, then S must decline or remain constant in absolute dollar terms. In this analysis, it is conservatively assumed that the real cost of control technologies remains fixed at its 1975 level. Therefore, the premium for low sulfur coal in the future should be equal to the current price differential.

Federal Power Commission data on contract prices of coal delivered to electric utilities are used to estimate the current price differentials between low sulfur coal and coal with an average sulfur content.(9) These differentials for each of the regions are added to the average value of coal to obtain mine prices for 1985.

Q. James Wade. You are optimizing for a single time period, feeding in updated data, and then reoptimizing for the second time period. Is the production cost curve that is used in the first time period the same function used in the second time period? Do you account for cumulative production in the use of the curve?

A. We start at a different point on the curve in each period, i.e., each succeeding period utilizes the data from the preceding period. Prices in each period are affected by the depletions of previous periods. Also, the rate of production from each mine is variable depending on the level of its reserves.

Coal Demand

Demands are externally introduced in accordance with prescribed scenarios and include all utility and industrial users of "steam coal," i.e., nonmetallurgical-grade coal. Metallurgical coal is excluded because its unique properties, which make it desirable for use in blast furnaces, command a much higher price than coal used for its energy content alone, i.e., steam coal.

The choice of demand regions is an integral aspect of an interregional market model. Using expansive and irregularly bounded regions would lead to highly distorted transportation costs between supply and demand points. An additional drawback to using large geographic areas, such as Census Regions, for demand regions, is that coal demand is not uniformly distributed. For example, Missouri, Ohio, and Pennsylvania use disproportionately more coal than other states in their respective Census Regions. (10) In addition, differing sulfur dioxide emission standards create non-uniform demands for low sulfur coal between regions and between utilities and industries within a given region.

Two versions of the ACM Model have been developed, having different levels of demand detail. In the two versions, the accuracy of model results is traded off against computer core requirements, cost, and turnaround time.

In the smaller versions, the U.S. is divided into 25 electric utility subregions. Demand centroids are chosen for each region based on considerations of geography, coal consumption, and proximity to transportation lines. Each demand centroid is near the demand-weighted geographic center of its region and on a major rail line. Industrial demand is concentrated in the Midwestern and Eastern states; 10 distinct demand centroids are used to capture these demands. The remaining demands are modeled as total aggregated demands. The demand regions and centroid cities are shown in Fig. 4.

Q. Jerry Eyster. How were the centroids determined?

A. By looking at the distribution of demand within each region. There was no formal methodology used.

Q. Charles Kolstad. Are we talking about demand for coal or for electricity?

A. Demand for steam coal in terms of Btu per year.

In the larger version of the ACM Model, demand for coal is divided among 52 geographical areas. Industrial centroids are separate from utility centroids for most regions. Some of the less significant industrial demands are combined with the corresponding utility demands to form a total of 98 distinct demand points shown in Fig. 5. The distinction between industrial and utility demand centroids allows more accurate analysis of the industrial sector. Transport costs as well as environmental regulations can differ significantly for utility and industrial coal users.

The coal market is quite rigid because of long-term supply contracts and the inability of boilers to efficiently use coal that is not of the quality for which they were designed. Total demand for coal is divided into portions that are either allocable or nonallocable. The nonallocable demand is that which is under long-term contract or that for which specific, reserved mine capacity has previously been opened.

Information on announced long-term contracts for delivery beginning in the 1977-1985 period is also incorporated into the model. (11) This is done by constraining the model to allow minimum flows between each supply

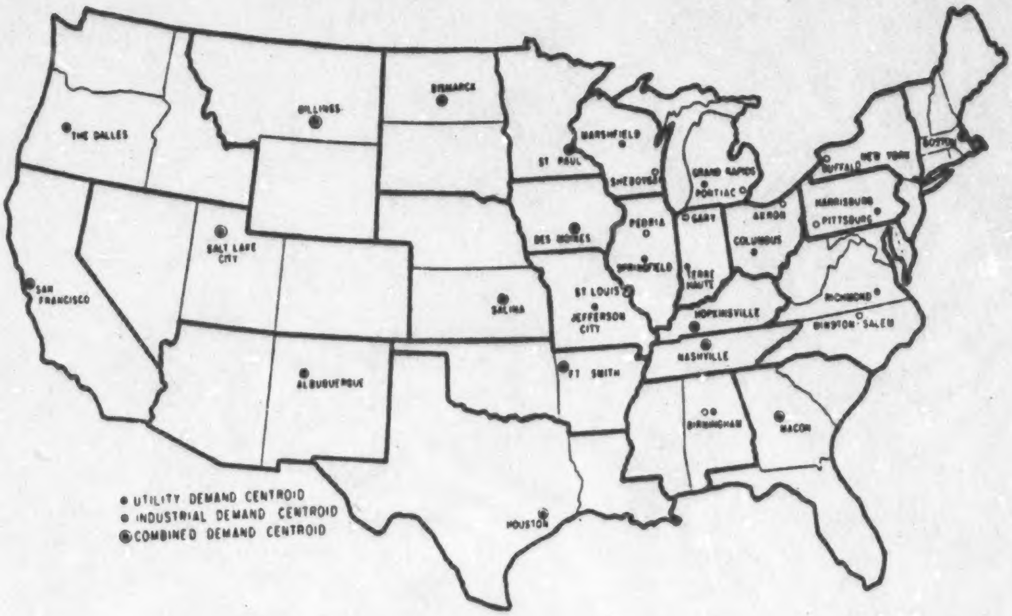
BISMARCK
BILLINGS
THE DALLES
MARSHFIELD
ST PAUL
SHEBOYGAN
GRAND RAPIDS
PONTIAC
NEW YORK
BOSTON
BUFFALO
HARRISBURG
PITTSBURG
AKRON
GARY
PEORIA
DES MOINES
SALT LAKE CITY
COLUMBUS
SPRINGFIELD
TERRE HAUTE
SAN FRANCISCO
ST LOUIS
SALINA
JEFFERSON CITY
HOPKINSVILLE
RICHMOND
WINSTON - SALEM
NASHVILLE
FT SMITH
ALBUQUERQUE
BIRMINGHAM
MACON
HOUSTON
● UTILITY DEMAND CENTROID
○ INDUSTRIAL DEMAND CENTROID
◉ COMBINED DEMAND CENTROID

Fig. 4. Demand Regions and Centroids (35 Demand Centers)

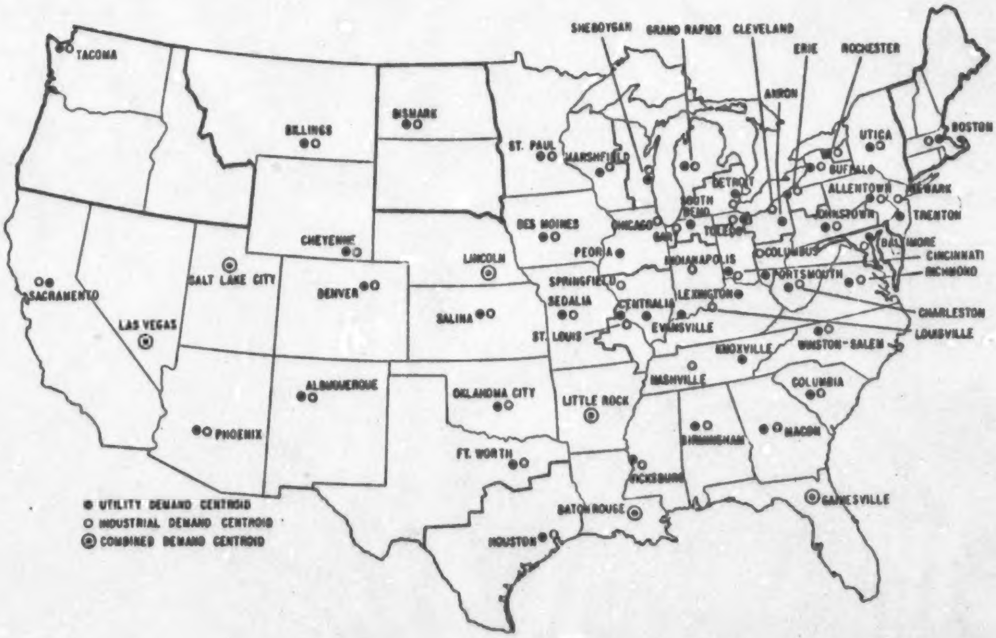
SHEBOYGAN
GRAND RAPIDS
CLEVELAND
ERIE
ROCHESTER
AKRON
TACOMA
BISMARK
BILLINGS
ST. PAUL
MARSHFIELD
UTICA
BOSTON
BUFFALO
DETROIT
ALLENTOWN
NEWARK
SOUTH BEND
JOHNSTOWN
TRENTON
DES MOINES
CHICAGO
GARY
TOLEDO
CHEYENNE
BALTIMORE
CINCINNATI
PEORIA
INDIANAPOLIS
COLUMBUS
LINCOLN
SALT LAKE CITY
RICHMOND
PORTSMOUTH
SPRINGFIELD
SACRAMENTO
DENVER
SEDALIA
LEXINGTON
CENTRALIA
CHARLESTON
SALINA
EVANSVILLE
LAS VEGAS
ST. LOUIS
LOUISVILLE
WINSTON - SALEM
KNOXVILLE
NASHVILLE
COLUMBIA
ALBUQUERQUE
OKLAHOMA CITY
LITTLE ROCK
PHOENIX
BIRMINGHAM
MACON
FT. WORTH
VICKSBURG
GAINESVILLE
BATON ROUGE
HOUSTON
● UTILITY DEMAND CENTROID
○ INDUSTRIAL DEMAND CENTROID
◉ COMBINED DEMAND CENTROID

Fig. 5. Demand Regions and Centroids (98 Demand Centers)

and demand area reflecting the magnitude of these announced contracts. The allocable demand is all completely new demand for coal plus any old demand for which the long-term supply contracts have expired. Demands for synthetic fuels derived from coal, for power generated at the minemouth and exports, are determined externally. Coal production necessary to satisfy these demands is subtracted from supplies available for shipment.

The coal-demands input to the model are based on the forecasts of the U.S. Department of Energy (DOE), with subsequent regional disaggregations. The DOE-PIES model (12) is a comprehensive energy model that generates fuel demands by end-use sector (residential, commercial, industrial, utility) within nine rather large divisions of the U.S. These regional demands for steam coal were disaggregated into 173 Bureau of Economic Analysis (BEA) regions by Oak Ridge National Laboratory using the Multiregion Model. (13) The DOE-PIES forecasts of utility and industrial coal demand and their BEA level disaggregations by Oak Ridge have been repeated for a number of alternative energy scenarios, e.g., a scenario to simulate a continuation of recent demand trends and a scenario to examine the impacts of the National Energy Plan. The BEA demand areas used by Oak Ridge were regrouped to correspond to the demand areas defined for the Argonne Model.

Transport Costs

Transport costs for coal are based on rail shipment. The transport cost submodel is based on a framework developed by Rieber and Soo (14) for unit-trains. Transport costs for a route (¢/ton-mile) are dependent on such variables as average tonnage shipped, length of haul, utilization factors, train speeds, and congestion. This framework is useful for forecasting rate increases as a function of the cost-component escalation (e.g., labor, fuel, materials). Transport costs for industry are equal to the scaled transport costs for utilities.

Q. John Green. We've analyzed the 1974 through 1977 ICC coal waybill statistics and found that the function which best describes the cost of transportation changes between 1974 and 1975 but remains relatively constant in 1975, 76, and 77. In each of the four years there's a clear break in the form of the function best describing data under 400 miles and over 600 miles. We get regression R^2s between .78 and .95 which we feel to be pretty good. The ICC Waybill statistics are based on actual tariffs.

A. A paper by Zimmerman suggests that there were some rents included in rail rates. We therefore prefer to use costs rather than rates since it's hard to measure the magnitude of the rents.

C. Rich Bernknopf. It is my impression Zimmerman mixed unit train and mixed freight rates in the same analysis.

C. John Green. We separated unit train, multiple car, and single car shipments and defined the best function for each class. Results using 1975 data were not too good but when we added data for the other years the results were more encouraging.

Q. Andy Van Horn. Can you explain what factors influenced rising costs? Do you include transshipment charges?

A. Transshipment charges are not included. I have no answer for the cost rising over distance except to agree that it's not what you would expect.

C. John Green. We found a very sharp decrease in cost between 0 and 400 miles and a much smaller rate of decrease between 600 and 1800 miles where it looked like the curve wanted to increase slightly.

C. Andy Van Horn. Not too many railroads have 1800 miles of track and cannot control costs in multiple railroad situations.

Environmental Control Costs

The definitions of the three coal categories employed in the model--low sulfur, intermediate sulfur, and high sulfur--are based on the types of technologies required for treatment of coal or flue-gases to meet environmental emission regulations for SO_2. Low sulfur coal is defined as coal able to meet an emission limit for SO_2 of 1.2 lbs/10^6 Btu heat input without application of treatment technology.

For intermediate sulfur coal, SO_2 emissions can be controlled before combustion by crushing the coal and mechanically washing and screening the particles to separate inorganic sulfur compounds from the coal. Alternatively, the sulfur problem can be handled after combustion by desulfurizing or scrubbing the exhaust flue gas of the boiler or furnace by passing it through a lime or limestone reagent. Although other advanced desulfurization techniques are under development (e.g., solvent refined coal, fluidized bed combustion), only conventional washing and scrubbing are considered in the model. Pollution-control costs depend on the source of supply and on the place where the coal is burned, because of regional differences in coal quality (mainly sulfur content) and "washability" (the ability to mechanically separate sulfur compounds from the coal) and differences in sulfur-dioxide emission regulations in the area of use. The washing costs estimated are net costs. That is, they include some of the savings associated with using washed coal, i.e., lower transport costs, higher heat value of the coal, etc. For intermediate sulfur coal, the decision to wash or scrub is made on the basis of least-cost. High sulfur coal is coal that must be scrubbed to meet environmental regulations. Coal that must be scrubbed to meet air emissions standards is penalized in the demand constraints to account for energy used in scrubbing.

Costs of sulfur dioxide control are formulated from information available through MITRE (15) and Argonne. Major inputs for these estimates are the government's performance standards for sulfur emissions from new plants, the heat content of the coal, and the sulfur and ash content of the coal. The air quality standards are specific to each demand center and type of user, i.e., industry or utility. Adjustments to these costs can be used to simulate a wide range of federal or state emissions standards.

Q. Charles Kolstad. What is the basis for the cost estimates?

A. Engineering functions. Generally, the scrubbing and washing costs include capital cost of washing facilities, scrubber equipment, taxes, utilization factors, operating and maintenance costs, and waste disposal costs. They are based on data from a number of sources including MITRE Corp., TVA, PEDCO, and Argonne engineers.

Q. Verne Loose. Is it possible for the model to both wash and scrub?

A. Not in any one demand center.

Q. Jerry Eyster. To what extent do you include washability characteristics of coal and ease of sulfur reduction? Is that what determines what's in the intermediate sulfur category?

A. Yes. High sulfur coal can only be scrubbed, low sulfur coal can be treated or not, and intermediate coal can be washed or scrubbed.

Data Integration

A flowchart illustrating the dynamic structure of the ACM Model is shown in Fig. 6. The model is run in five-year increments. Information generated in one time period affects costs and allocations in the next time period through the dynamic adjustment of demand data, illustrated in Fig. 7, and supply functions, illustrated in Fig. 8.

PREVIOUS USES OF THE MODEL

BACT Study

The Clean Air Act amendments passed by Congress in August 1977 required that the federal New Source Performance Standards (NSPS) be

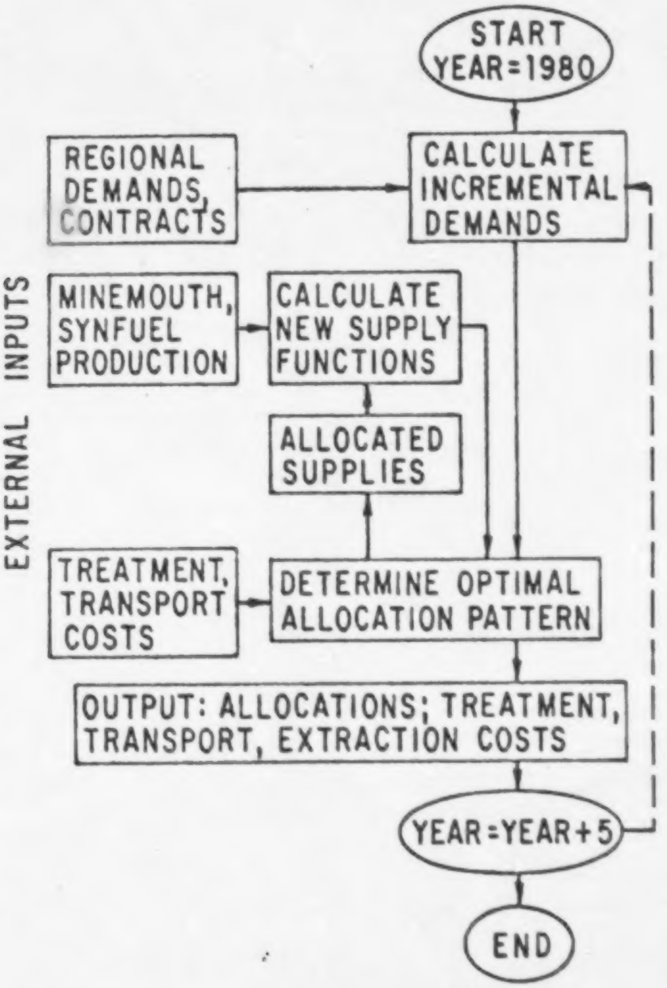
START
YEAR=1980
REGIONAL DEMANDS, CONTRACTS
CALCULATE INCREMENTAL DEMANDS
EXTERNAL INPUTS
MINEMOUTH, SYNFUEL PRODUCTION
CALCULATE NEW SUPPLY FUNCTIONS
ALLOCATED SUPPLIES
TREATMENT, TRANSPORT COSTS
DETERMINE OPTIMAL ALLOCATION PATTERN
OUTPUT: ALLOCATIONS; TREATMENT, TRANSPORT, EXTRACTION COSTS
YEAR=YEAR+5
END

Fig. 6. Argonne Coal Market Model Flowchart

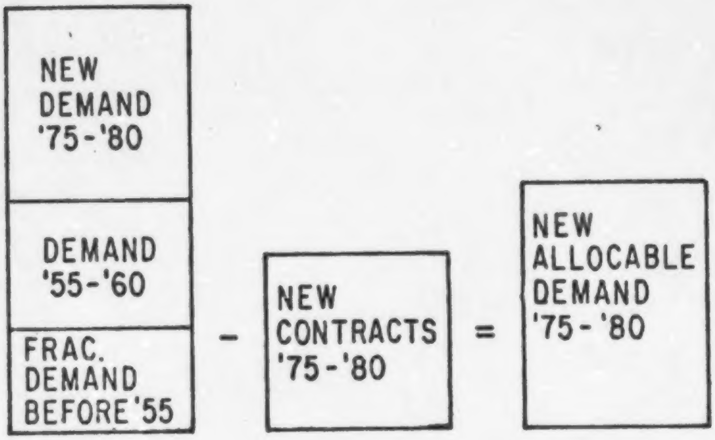
NEW
DEMAND
'75-'80
DEMAND
'55-'60
FRAC.
DEMAND
BEFORE '55
-
NEW
CONTRACTS
'75-'80
=
NEW
ALLOCABLE
DEMAND
'75-'80

Fig. 7. Dynamic Demand Adjustment

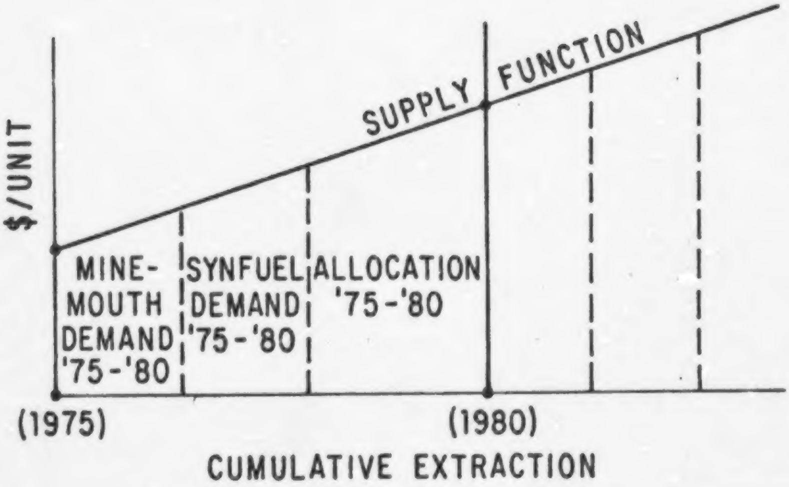
$/UNIT
SUPPLY FUNCTION
MINE-
MOUTH
DEMAND
'75-'80
SYNFUEL
DEMAND
'75-'80
ALLOCATION
'75-'80
(1975)
(1980)
CUMULATIVE EXTRACTION

Fig. 8. Dynamic Supply Adjustment

revised to reflect the best technological system for continuously reducing emissions of air pollutants, referred to here as the Best Available Control Technology (BACT) policy. One use of the model was to examine the effects on regional coal markets of different implementations of the Clean Air Act Amendments.(16) Four policy directions (BACT scenarios) were analyzed in 1977 because at that time, the EPA had not yet defined an official BACT policy:

90% sulfur removal--an across-the-board percentage reduction of the naturally occurring sulfur content of coal,

0.6 lb SO_2--assumes a tightening of permissible emissions to a limit of 0.6 lb SO_2/million Btu,

0.5 lb SO_2--assumes a tightening to 0.5 lb SO_2/million Btu, and
National Energy Plan--assumes implementation of all coal-related provisions, including Best Available Control Technology, of the National Energy Plan as presented to Congress by the Carter Administration.

The effects of these scenarios and a "base case" (continuation of present laws) were simulated. The magnitude and direction of the shifts in interregional coal flows are illustrated in Fig. 9. For the 90%-sulfur-removal scenario, it shows flows of coal from the Northern Great Plains to the East Central demand area dropping substantially relative to the base case for the same year (40 million tons versus 180 million tons), while shipments from East Central to Southeast nearly triple. The following conclusions were drawn regarding the effects of BACT on production and interregional flows of coal:

1. Any BACT policy will have little effect on coal markets before 1985, but will substantially alter market patterns between 1985 and 1990 because:
    (a) the BACT provisions will probably exempt coal plants now under construction that have already obtained permits to burn Western coal and these plants' coal contracts will account for nearly all of the growth in Northern Great Plains (Wyoming and Montana) production through 1985 and
    (b) it will be difficult to achieve significantly new production capacity in the Interior Coal Province (defined

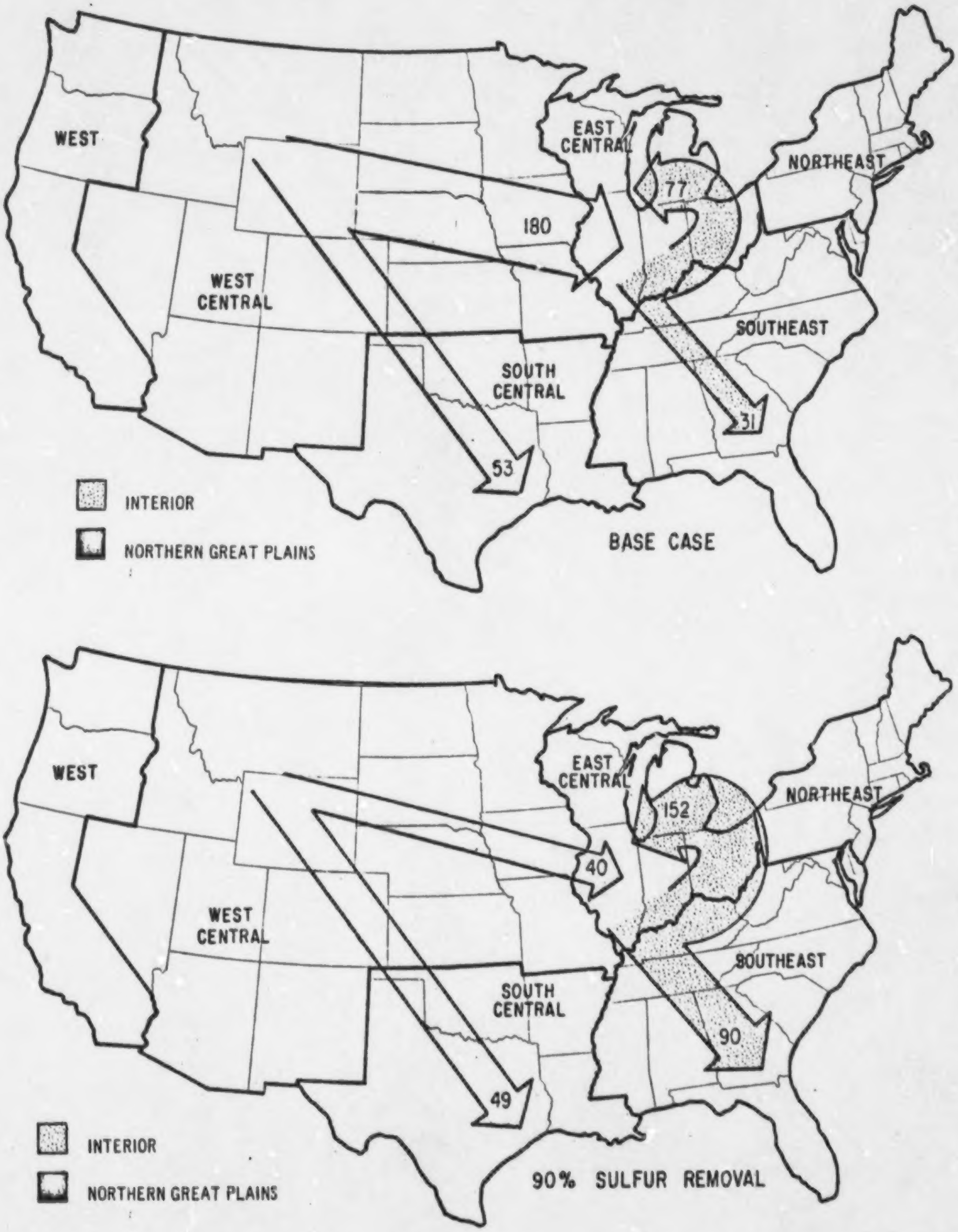
WEST
EAST CENTRAL
NORTHEAST
WEST CENTRAL
SOUTH CENTRAL
SOUTHEAST
77
180
31
53
INTERIOR
NORTHERN GREAT PLAINS
BASE CASE
WEST
EAST CENTRAL
NORTHEAST
WEST CENTRAL
SOUTH CENTRAL
SOUTHEAST
152
40
90
49
INTERIOR
NORTHERN GREAT PLAINS
90% SULFUR REMOVAL

Fig. 9. Changes in Interregional Coal Flows to Major Demand Areas Resulting from BACT Policy (Millions of Tons Shipped, 1990)

as Illinois, Indiana, Western Kentucky) before 1985. For this reason some prospective buyers may seek coal supplies from the Northern Great Plains as a hedge against coal shortages in the East.

2. All the BACT scenarios trade off coal from the Northern Great Plains for Interior coal, especially after 1985. However, production levels in the Northern Great Plains will remain at boom levels through 1985. This production will serve many of the major coal-demand areas in and around the Interior Coal Province.

3. Under any BACT policy considered here, Interior coal producers soon recapture most of their traditional markets (e.g., Illinois, Indiana, Missouri, Iowa) lost partially or entirely to Western and Northern Great Plains coal suppliers.

4. Interior coal will also penetrate more heavily into the Southeast.

5. Producing areas in the West and Gulf will be affected very little by a BACT policy.

6. Alternative BACT scenarios have minor effects on each region's share of production. The 90% sulfur removal requirements would cause the largest shift in production from the Northern Great Plains to the Interior, but even in 1990 this shift differs from other BACT scenarios by less than 10 million tons per year. In most cases, the differences in regional production across scenarios are less than 5 million tons in both 1985 and 1990.

Great Lakes Study

The Argonne Coal Market Model was used to simulate environmental and market conditions around five Great Lakes ports to determine the industrial demand for Western coal in the Great Lakes region. (17) The ports of Buffalo, Erie, Cleveland, Toledo, and Detroit were considered.

Implementation of the Clean Air Act Amendments of 1977 posed significant uncertainties for analyzing the market potential of Western coal. The principal regulation that would affect the economics of (and the market demand for) Western coal is of the SO_2 removal standard. Several alternative SO_2 standards were defined and simulated in the model. In addition to environmental variables, the effects of various transshipment distances on the demand for Western coal shipped to eastern Great Lakes ports were tested. In these scenarios, it was assumed that Western coal was delivered by high volume shipments to end users. The distances of this second rail shipment were varied from 25 to 75 miles to determine the extent of the market penetration, if any, of Western coal inland from the Great Lakes.

Results indicate that under the least stringent case, i.e., the standards that existed prior to the Clean Air Act Amendments of 1977, Western coal is preferred to Eastern coal in all the major Great Lakes ports studied. This preference was found in both 1985 and 1990 in the immediate vicinity of all five port cities. Detroit is the only port in which Western coal is competitive with Appalachian coal more than 25 rail miles from the dockside. Other environmental scenarios were examined. The effect of further tightening the industrial new source performance standard was especially interesting for the analysis. The allowable sulfur emission limit was lowered to 1.0 lbs/10^6 Btu of heat input. The model simulations show that any further tightening of these emission standards for industry will greatly reduce the demand for Western coal in the Great Lakes ports areas. None of the five ports had any demand for Western coal outside the immediate vicinity of the port in either 1985 or 1990.

Gasifiers in Industry Study

In this study, future coal allocation patterns and costs for industrial coal markets were estimated with the ACM model as inputs to a siting analysis for industrial low-Btu gasifiers. (18) Industrial and utility demand projections, formulated at Oak Ridge National Laboratory, were input to the 98-demand centers version of the ACM Model. Using this model version allowed the analysis for industry to be done separately from utilities but within the context of national coal allocation patterns.

The first set of runs consisted of a base case where coal use projections to the year 2000, not including gasifier demand, were input to the model. Also, sensitivity runs were made to test the effect that reduced coal transport costs for industry, due to the existence of regional coal brokers, would have on allocation patterns and coal costs. A subsequent set of runs was made with the increment of coal demand due to gasifier penetration, provided by ORNL, to ascertain sources and costs of coal for the gasifiers. That concludes my presentation.

Q. James Wade. I would not call this a forecasting model. A forecasting model attempts to predict what will occur at some point in time. This model assesses alternative scenarios in terms of the policy costs of alternative variables. The same is probably true of the other models we will be talking about at this workshop. Also you call this a market model but we are looking at a linearized supply section. Is linearizing the demand sector relevant in this model? I feel it is a relevant question in terms of evaluating the substitution effects in this type of policy model. What about using a step function on the supply side and making demand a function of price?

A. I have used the term forecasting loosely but through sensitivity analysis with the model the certainty of some results in future years becomes close to point forecasts. Demand is inelastic in the model and a solution represents patterns of allocation for a particular scenario of coal demand. Macroeconomic and growth assumptions are part of each demand scenario. I don't see why the representation of the supply sector with step functions would add anything to the analysis. The ICF supply functions contain many steps and I don't think linearizing them loses any information given the uncertainties in the data on which they are based. We linearize because the quadratic program can be solved more quickly by performing the optimization with this kind of representation. It would be nice to have price sensitive demand functions in the model and with the quadratic formulation. It's not that much of an extension given the system already contains price sensitive supply functions. It would require the specification of a number of new variables equal to the number of demand centers. However, incorporation of interfuel substitution effects would greatly complicate the model. How much sense does it make to have elastic coal supply and demand curves unless you base those curves conditionally on the prices of other fuels which would have to be estimated independently of the coal model? The net effect of the inelastic demand representation and linear supply functions is an attempt to separate the problem of coal modeling from the interfuel competition question.

Q. James Wade. I think the linearization of the supply function adds a complication and that you could solve the linear programming problem easily without losing detail. Then you could add detail on the demand side to make it a more integrated model.

C. I believe that a large number of coal market issues can be adequately analyzed by using a model which bases coal demand projections conditionally on the projected prices of coal and substitute fuels. This requires that after each model run, the coal price projections upon which the coal demand projections were made be compared with the coal price projections obtained from the Coal Market Model solution. Iterations may be needed to insure that these two price projections are made reasonably comparable. The PIES Model of DOE is a large LP which includes much detail on energy demand. Several fuels and substitution potential are modeled. However, the large size, complexity and data requirements of such a comprehensive model tend to limit the amount of detail (geographical and other detail) that is devoted to a particular fuel market. In other words there is judgmental tradeoff between the cost of producing and running such a model and the value of information that can be obtained from the model.

Q. Rich Church. You've given a formulation which is a quadratic programming problem. Could you describe your solution technique and your success with this size of problem?

A. The quadratic program used a computer optimization code developed by System Optimization Laboratory. We received the computer tape from Stanford and implemented it on our IBM system. We had trouble compiling the code; to get the code compiled was a bigger job than formulating the model and collecting the data. The dimension of the code had to be expanded because of the size of our problem.

Q. Rich Church. I think Dr. Wade's suggestion about solving other formulations is an appropriate one. Have you solved this problem both quadratically and linearly and compared the results?

A. About three years ago I developed a pilot, linear programming representation to deal with coal allocation problems. The decision was made not to use it but to develop the quadratic problem. This decision was based on the number of variables required to solve the problem and its size. In a linear program representation each variable must be defined with an i subscript corresponding to each supply center, with n corresponding to each step in the cost function, and with j corresponding to coal from each step on the supply function for each supply area.

Q. Rich Church. But the curves you showed us were relatively smooth and flat which means little discontinuity. Once you solve a time period you shove yourself further up each curve and you can use new production values to feed back into the linear programming problem. Since the curves are flat you would always be close to the correct solution. If the curves weren't flat, but had a constant slope, the problem would still be easy to solve.

Q. Jerry Eyster. In one of the applications of your model we see that there are large regional shifts between the base case and the scenario solution. How much of that large shift is the result of large supply regions?

A. I can't speculate on the disaggregation effect. The base case and the scenario run both used the same supply and demand assumptions. The question is how disaggregated do we want to get if we don't have sponsors interested in small area analysis.

C. Verne Loose. The only way to respond to the question of the correct level of disaggregation is to build multiple models similar in all respects except for the level of regional disaggregation.

Q. Jerry Eyster. I disagree that you would have to build back to look at the solution. You can identify if there are specific break points by doing sensitivity analysis. The problem is that with big regions you have big volumes of coal and at the break point there are big shifts. Have you investigated whether these are break points with your model formulation?

A. No.

C. George Ferrell. We've gotten similar large changes in Western coal use as a result of changes in scenarios using our Utility Simulation Model so I think the issue is insensitive to the level of regional aggregation.

C. Andy Van Horn. To elaborate on what George said, we used a different modelling approach and got similar results but we also performed sensitivity analysis with certain scenarios. Factors such as sulfur content, prices, transportation, escalation rates, and economic rent are more important than where in a specific supply region the coal came from.

Q. Charles Kolstad. Whether it is reasonable to step through time as your model does depends on the speed with which you move along the supply curves. It becomes an economic rent question. How fast does the marginal cost go up over time for specific supply areas?

A. It depends on the scenario and the characteristics of demand centers. Different supply areas go up at different rates. Conceptually, there is a limit to how fast production can increase from a coal supply area and still have the original coal supply function remain valid.

Q. Charles Kolstad. Can you do this one step at a time or can you do it simultaneously over the whole time period. If you don't go up quickly the two solutions will be the same; if you do go up quickly they may be radically different.

A. Your point is well taken. It would be worthwhile to perform sensitivity analyses on how the size of the time step (currently five years in the model) affects the model results. Also it would be instructive to compare the results with those from a model which solves for all time periods simultaneously using a resource producer revenue maximization scheme such as the SRI-Gulf Model.

Q. Andy Van Horn. Have you taken the 1980 results and compared them with 1977 or 1978 coal flows to see how close you come to current circumstances?

A. Greg Krohm performed that validation and found the results to be quite reasonable.

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THE OAK RIDGE SCOAL MODELS*

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INTRODUCTION

This paper presents several models from a System of COAL models (SCOAL) designed to analyze the implications of coal use in the United States. SCOAL considers power plant siting at national and multistate regional scales, coal transportation through the railroad system, and electricity transmission. The emphasis of this paper is on the transportation models, although other models will be presented.

The first part of the paper discusses the general approach to the formulation of SCOAL, and several major differences between SCOAL and other models that have been developed to analyze coal activities. The second part provides an overview of SCOAL. The third section gives formulations of the national scale power plant siting models, the coal transportation models, and the electricity transmission models. All of the SCOAL models have been formulated as linear programs (L.P.s). However, the national siting models can be solved more readily using a heuristic solution procedure, and the procedure will be discussed in conjunction with these models.

The model formulations presented in this paper are the initial development of SCOAL. The formulations presented here consider factors that we believe to be important in the analysis of coal movement and its use in the electric utility industry. Industrial uses, gasification, and liquefaction will be added in the future. The final section of the paper will discuss these and other extensions to the formulations presented here.

We should emphasize that the formulations in this paper have not yet been applied to real data. Some of the necessary data are available at the Oak Ridge National Laboratory, and the remaining data are presently being acquired, verified, and made useful. It is entirely possible that the formulations presented below may be changed as experience is gained in their use.

FACTORS CONSIDERED IN THE DEVELOPMENT OF SCOAL

This section considers three factors that have guided the development of SCOAL and which set it apart from other models for the regional analysis of coal activities. These are the need for a system of models, the desirability of using physical quantities instead of activity costs, and the need to consider equity within the coal activity system.

A System of Coal Models

Analysis of the implications of increased coal use requires the ability to examine several different activities at several different levels of detail. The coal will be mined in some locations. Much of it will be burned in other locations, thereby requiring transportation. Much of the coal will be used to generate electricity, requiring the siting of power plants and the transmission of power. Burning the coal will affect air and water quality, and the amount of water consumed in a region. Models of each of these activities require different levels of information. For example, to consider national coal transportation patterns, we need good estimates of how much coal of different types will be mined, how much of different types will be burned, the locations of these activities, and a representation of the transportation system. If this information is available in an appropriate form, the model used to analyze transportation flows will require little explicit information about the effects of coal combustion on air or water. On the other hand, the analysis of environmental and transportation problems within any specific region will require detailed information about power plant sites, stream flow, emissions to the atmosphere, as well as the transportation network within the region. This analysis for a specific region may require little information about the shipment of coal into the region, beyond knowing where, how much, and what type of coal does enter. This comparison illustrates the need for different types of detail in the analysis of different aspects of coal use. Other examples could be cited.

One way to meet the need for different types of detail is to develop a model that encompasses all necessary detail. If the model is to remain tractable, however, some compromise must be made between the spatial coverage of the model — e.g., nation, region, or state — its spatial detail — e.g., regions, states, or counties in a national model — and the detail with which it models coal activities — e.g., coal types, pollutant dispersion, and transportation capacities. An alternative approach, and the one adopted in SCOAL, is to develop a system of interrelated, complementary models, each with its own compromises in these areas, that can be used together to answer coal-related questions.

3

Use of Physical Quantities

The SCOAL models emphasize the measurement of physical quantities, such as ton-miles of coal movement or number of power plant sites, rather than the costs of these quantities. This reflects several assumptions about the coal activity system and the use of the SCOAL models. The first of these is that the major components of cost can be modeled in ways that will tend to minimize costs. Thus, for example, the national siting models minimize ton-miles of coal movement, minimize megawatt-miles of electricity transmission, minimize the impact of power plants on their sites, and ensure that power plants are of a reasonable size. When cost consists of several components, as it does in the national siting models, the models are multiobjective. This reflects the increasing tendency for choices between major components of cost to be influenced by political decisions as well as by purely economic factors. Even if accurate cost information were available, it would not be the sole or necessarily even the major basis for decisions involving the coal activity system.

In addition, however, most applications of SCOAL will concern conditions in the future, but accurate cost data will not be available for future time periods. Estimates of future costs and the relative costs of different activities in different regions are subject to error, and the models are sensitive to errors much smaller than those likely in future cost projections. Obviously these errors can affect the detailed results of such models, by rerouting a flow or by placing a power plant in one county instead of another. What is less obvious, however, is that small errors may affect the gross results of a model, shifting an entire pattern of activity from one part of a region to another.

Obtaining cost information requires substantial effort, yet the information is not essential and, if errors are large enough, it may even be counter-productive. Cost coefficients can be added to the objective functions of the SCOAL models if desired, but the use of simple physical quantities will be adequate, it not preferable, in most analyses.

Q. Verne Loose. Please reiterate your rationale for rejecting price and cost information in favor of using physical quantities?

A. My experience indicates that small changes in cost can cause significant differences in a final solution. If the outcome of a model is very sensitive to prices then, in order to include price information into a model, the investigator must have confidence in the input prices and costs or seriously question the results. We have rejected the use of prices in the national model to avoid sensitivity problems resulting from questionable estimates of prices and costs. We are looking for robust patterns generated by the use of physical quantities. In addition, minimization of physical quantities is likely to minimize costs as well.

A. Ed Hillsman. The point that small differences in costs can radically change the solution has already been mentioned in discussion of the Argonne Model. We wish to avoid that problem. We can put prices into our model later if it is desired.

Q. Jerry Eyster. But how do you make trade-offs between one physical quantity and another physical quantity when in fact the issue is you can site a power plant where you minimize the coal haul but have a long transmission distance or minimize the transmission distance and have a long coal haul. I have yet to figure out a way except for costs that one can basically make that kind of trade-off where the units are different.

A. I think you have a very appropriate question. The siting models are cast as multiobjective programming problems. Such a model can be solved for the trade-off between transmission distance and coal haul by many types of solution techniques. I suggest that a text on Multiobjective Programming by Jared Cohon might answer all of your questions. Such a trade-off is precisely the purpose of casting a problem in a multiobjective framework.

Equity

Another difference between SCOAL and other models is SCOAL's ability to consider equity for individual entities within the coal activity system. Spatial optimization models tend to consider a region and the activities within it as an integrated system. SCOAL models make similar assumptions. However, a regional system results from decisions by individual electric utilities, separate industries, private railroad corporations, and individual mining companies. An efficiently run system may place some of these individuals at a substantial disadvantage, particularly if the system changes over time.

For example, as currently planned power plants begin to operate, the amount of coal shipped will increase, and some parts of the transportation system will become congested. Once a critical part of the transportation system begins carrying its maximum amount, then additional shipments raise equity problems. Some existing flows must be rerouted to permit new flows to move efficiently, or the new flows must be routed inefficiently, perhaps over very circuitous routes. In either case, one or more shippers and their respective regions are placed at a relative disadvantage. One obvious option in this example would be to increase the capacity of the congested rail links. However, it may be possible to reroute much of the congested traffic over good alternative routes so that no individual shipment bears an undue share of the burden of congestion.

A similar situation can arise for utility companies and power plants, as good sites are used and companies begin to build power plants outside their service areas. In this case, equity questions are raised by the allocation of scarce, good sites. As in the transportation example above, several of the SCOAL models can develop alternative patterns of activity that limit the burden borne by any individual, while keeping the regional system as efficient as possible.

OVERVIEW

The models in SCOAL have been formulated to consider several specific issues in the analysis of coal use. The first issue arises when a national policy is discussed to increase the use of coal (Fig. 1). We would like to obtain estimates of where coal will be used in the nation and, to some extent, the amounts and types to be used in different regions. The national siting models in SCOAL address this issue. They take projected national or regional demands for electricity and select locations for the new power plants required by the projections. Potential locations will be counties or, in parts of the West, smaller areas. The siting models are optimization models with four objectives, but their use is intended to provide a representative, baseline pattern of locations that can be used by other portions of SCOAL.

The regional siting model for SCOAL has not yet been formulated. This model would take the total amount of electric generating capacity projected for a region by one of the national models and consider factors that are important at the regional rather than the national scale. The regional model will consider some of the factors from the national model with greater spatial detail, or with more detailed modeling

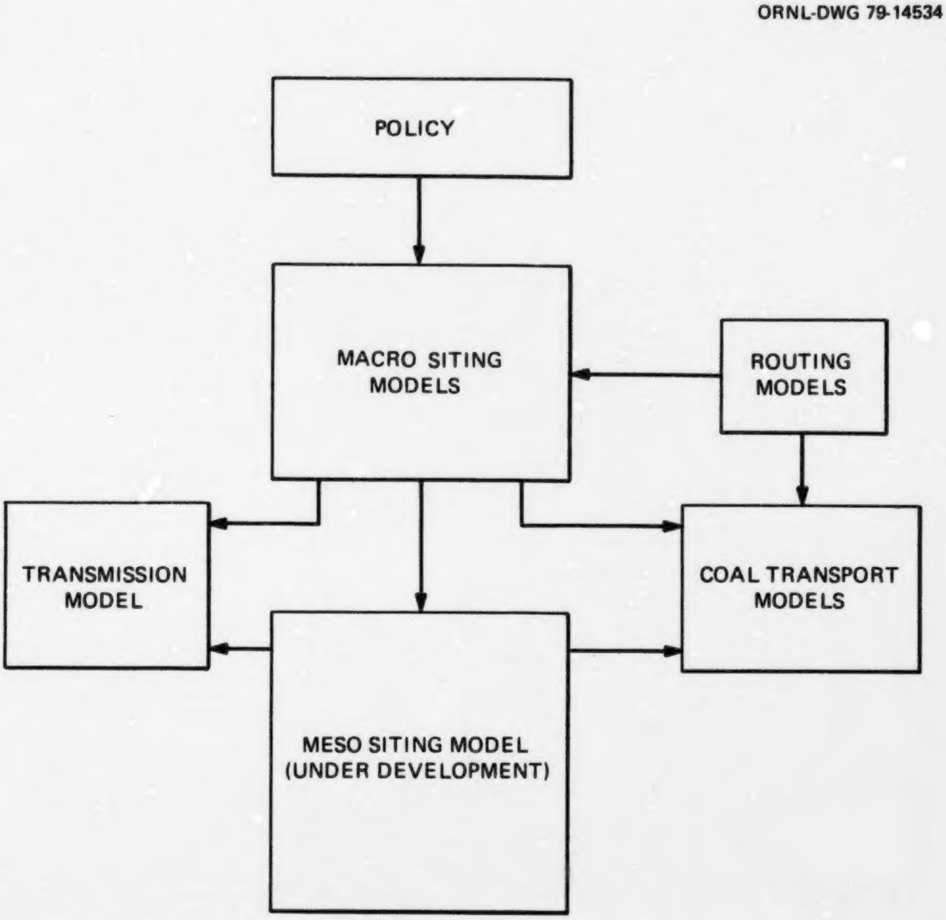
ORNL-DWG 79-14534
POLICY
MACRO SITING MODELS
ROUTING MODELS
TRANSMISSION MODEL
COAL TRANSPORT MODELS
MESO SITING MODEL (UNDER DEVELOPMENT)

Fig. 1. Flows of information in SCOAL.

in conjunction with the national siting models to provide regional estimates of national coal use. A third model, structured as a transshipment model, differentiates among coal types and also considers the ability of the transportation system to handle the flows. The two remaining transport models can also consider the existence of contracts for coal that have, in effect, reserved parts of the available transportation system for use by current or proposed power plants. These models might be used for in-depth analysis of a specific region or for national analyses. The transportation equity issue discussed earlier is treated in one of these models.

Finally, SCOAL has a separate model to consider transmission of electricity. The model as it is presently structured is purely a regional analysis tool, capable of examining gross flows of electric power within a region of the nation. Future development of this model will consider cooperation between utility companies.

NATIONAL AND REGIONAL SITING MODELS

The SCOAL model system at this time contains two proposed national facility siting models. The purpose of these two models is to provide an estimate of future patterns of coal use. The estimate is based on regional energy requirements that are projected apart from the model. The patterns generated by the national siting models can be analyzed in detail by the regional siting model and by the transportation and transmission models. Both the regional and national siting models are cast as multiobjective programming problems. The national models will be called MACRO and the regional model will be called MESO.

of the processes of coal use. It will consider other factors as well, including the equity issue raised earlier. The regional scale model can be used region by region to fine tune the results from the national model, to provide a better baseline location pattern. Alternatively, the regional model could be used as a regional planning tool, to examine the locational effects of different state or regional policies on the national projections.

SCOAL contains two coal routing models and five coal transport models. The routing models seek a path through a transportation network for a shipment between a given origin and a given destination. One routing model seeks to find the best route within a single railroad, while one seeks routes where several railroads must handle the shipment. Both models are presently formulated for use on a 16,000 node representation of the U.S. railroad system. We anticipate extension of these models to include barge and some shorthaul truck traffic. Both models can be made to generate a range of alternative routes for a given shipment, although the presentation of the models will be confined to single routes. These routing models can be used to examine the routes that might be used when a new power plant or a new coal mine begins operating. They also generate much of the data required by the coal transport models and the siting models.

The coal transport models consider the total transportation pattern of flows between all coal sources and all coal destinations. The transport models include two simple transportation problems that can be used to estimate efficient gross regional flow patterns, either with or without the treatment of different coal types. These models might be used

Both MACRO and MESO models seek sites for new power plants to meet four objectives: (1) minimize ton-miles of coal shipments, (2) minimize megawatt-miles of electricity transmission, (3) minimize the number of sites that have an estimated size less than some minimum capacity; and (4) maximize the acceptability and the suitability of generation types and size for the sites that are chosen. Only the details of the MACRO models are discussed in this report.

MACRO 1 assumes that the coal supply is known for each power plant F2
site that may be used in a given region (Fig. 2). MACRO 2 seeks the best source of supply for each new power plant, given limits on the availability of certain types of coal from certain mining districts F3
(Fig. 3). Both models require a national projection of demand for electricity from coal, disaggregated to load centers such as Bureau of Economic Analysis areas (BEAs). The MACRO siting models do not work with capacity limits on transportation or transmission links; questions of congestion are left to the transport and transmission models introduced in a later section of this paper. Because specific link information is not needed, the network need not be represented explicitly within the model, and the locations of demand centers and potential power plant sites may be represented by coordinates. Distances between points may then be computed using functions calibrated to approximate distances measured through the actual rail or transmission networks. Love and Morris (1975) have discussed methods of estimating such functions. This approach to handling distances will enable the models to be solved efficiently for large numbers of locations. The notation used in the first MACRO model is as follows:

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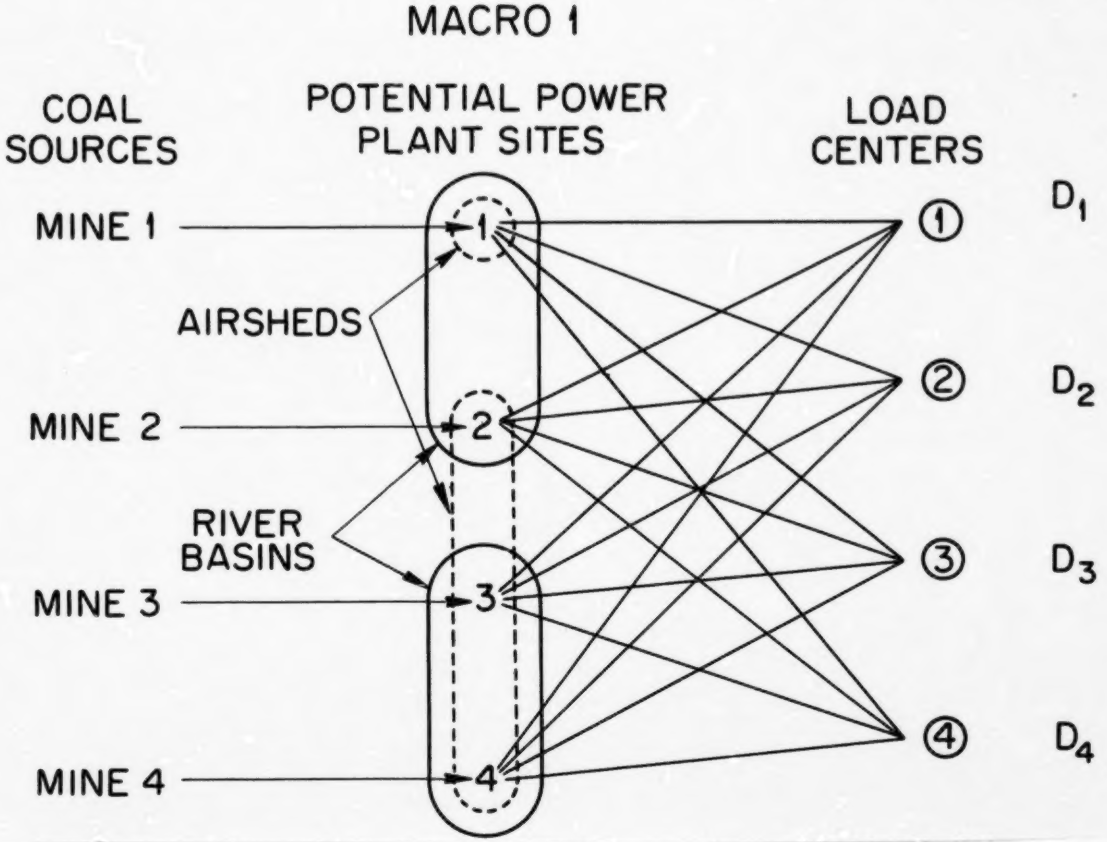
MACRO 1
COAL SOURCES
POTENTIAL POWER PLANT SITES
LOAD CENTERS
MINE 1
MINE 2
MINE 3
MINE 4
AIRSHEDS
RIVER BASINS
1
2
3
4
①
②
③
④
D1
D2
D3
D4

Fig. 2. Structure of MACRO 1, with predetermined source of coal for each potential power plant site.

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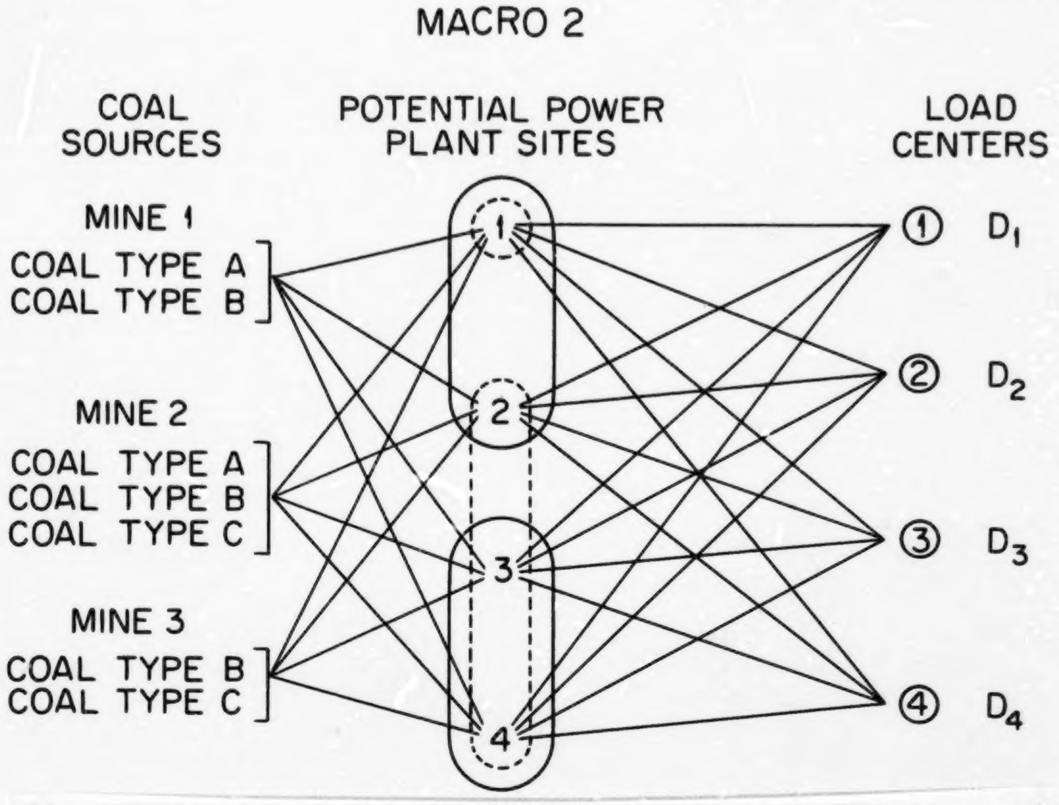
MACRO 2
COAL SOURCES
POTENTIAL POWER PLANT SITES
LOAD CENTERS
MINE 1
COAL TYPE A
COAL TYPE B
MINE 2
COAL TYPE A
COAL TYPE B
COAL TYPE C
MINE 3
COAL TYPE B
COAL TYPE C
1
2
3
4
①
②
③
④
D1
D2
D3
D4

Fig. 3. Structure of MACRO 2, with coal source and coal type for each potential power plant source to be chosen by the model.

$$x_j = \begin{cases} 1 \text{ if site j is used} \\ 0 \text{ if site j is not used} \end{cases}$$

$$y_j = \begin{cases} 1 \text{ if site j is smaller than LSITE or } LMIN_g \\ 0 \text{ if site j has established capacity greater than LSITE} \\ \text{and } LMIN_g \text{ or if no capacity is established at site j.} \end{cases}$$

f_j^g = the number of units of generation type g located at site j.

$\bar{e}_{ji}$ = the fraction of demand at i supplied by the facility located at j.

D_i = the demand for electricity at area i.

DS_j^g = the distance to the designated coal source for generation type g located at site j.

$tons_g$ = tons of coal needed to support one unit of generation type g.

β_g = capacity factor, percentage of total capacity that plant type g produces on the average.

D_{ji} = the distance from facility site j to demand area i via known transmission route.

I_j = overall impact of site j.

I_j^g = impact of site j per unit of generating capacity of type g.

$LMIN_g$ = the smallest amount of capacity of generation type g that is justifiable at any location.

LSITE = the smallest amount of capacity, summed over all generation types, that is justifiable at any location.

$LMAX_j$ = the maximum amount of capacity that can be developed at site j.

w_g = the amount of water needed for cooling and other purposes per unit of added generation f_j^g.

A_j = total amount of water available at site j.

u(j) = the set of sites upstream of facility site j.

1. Each demand area must have its total needs supplied.

$$\sum_j e_{ji} = 1 \quad \text{for each area } i$$

Q. Verne Loose. Does this imply you are supplying transmission from one area to another? Are you summing j for each i?

A. We are summing e_{ji} over j for each i. We do not have an embedded transmission network but are assigning loads based on knowledge of distances. In the objective function e_{ji} is the fraction of the total demand at load center i supplied by a power plant in county j.

2. The total capacity developed at area j must be greater than or equal to the demand that is supplied by that area.

$$\sum_i D_i \bar{e}_{ji} < \sum_{g \varepsilon G} \beta_g f_j^g$$

3. Definition constraint for determining whether, when capacity of type g is built in area j, the amount of type g capacity is justifiable ($y_j = 0$) or not ($y_j = 1$).

is

$$f_j^g > \text{LMIN}_g \, (x_j - y_j)$$

4. Definitional constraint for y_j based on the total capacity established at site j.

$$\sum_{g \varepsilon G} f_j^g > \text{LSITE} \, (x_j - y_j)$$

5. Constraint establishing an upper bound on the total amount of capacity located at site j.

$$\sum_{g \varepsilon G} f_j^g < \text{LMAX}_j \, (x_j)$$

$\alpha^{p}_{j,n}$ = air pollutant transmission coefficient. The fraction of pollutant p emitted at j that is measured at sector n.

E^{g}_{p} = emission rate per unit of generation type g for pollutant p.

S^{p}_{n} = maximum level of pollutant p at sector n.

The four objective functions of MACRO 1 can now be given:

Objective 1: Minimize total transport of coal in ton-miles.

$$Z_1 = \sum_{g \varepsilon G} \sum_{j \varepsilon J} \beta_g \; \text{tons}_g \; f^{g}_{j} \; DS^{g}_{j}$$

Objective 2: Minimize total transmission of electricity in megawatt-miles.

$$Z_2 = \sum_{j \varepsilon J} \sum_{i \varepsilon I} D_i \; \bar{e}_{ji} \; D_{ji}$$

Objective 3: Minimize the number of sites that have an established size less than a certain capacity, LSITE.

$$Z_3 = \sum_{j \varepsilon J} y_j$$

Objective 4: Minimize the impact of the sites chosen as well as the impact of the size and type placed at a given location.

$$Z_4 = \sum_{j \varepsilon J} I_j x_j + \sum_{j \varepsilon J} I^{g}_{j} \; f^{g}_{j}$$

The constraints for MACRO 1 have two purposes: (1) to define the value of a variable used in one of the objective functions and (2) to prevent certain conditions from occuring such as requiring more water from an area than what is available. The constraints are as follows:

with regularity in many solutions to the L.P. model. The definition of the minimum type and site size was defined in the third and fourth constraints and would also have to be removed in order to simplify the problem to an L.P. If we further eliminate the airshed constraints and keep limitations site specific we can simplify the MACRO 1 model to the following problem:

MACRONET 1:

$$\text{Min} \sum_{s=1} \sum_{i} w_1 E_i x_{si} + w_2 d_i x_{si} + w_3 t_{is} x_{si}$$

$$\text{S.T. (1)} \quad \sum_{s} x_{si} + f_{ji} - f_{ik} = 0 \qquad \text{for all } i \text{ where } j \varepsilon \overline{U}(i) \text{ and } k = \overline{D}(i)$$

$$\text{(2)} \quad f_{ji} \leq A_j \qquad \text{for all } i \text{ where } j = \overline{U}(i)$$

$$\text{(3)} \quad \sum_{i} x_{si} = p_s \qquad \text{for each } s$$

$$\text{(4)} \quad \sum_{s} x_{si} \leq C_i \qquad \text{for all } i$$

$$\text{(5)} \quad f_{ji} \text{ , } x_{si} \text{ integer.}$$

where

x_{si} = number of plant units located in area i serving load center s.

t_{is} = transmission distance from area i to load center s.

f_{ji} = number of plant units built at j where $j = \overline{U}(i)$ plus the number of plant units built upstream of j. $(f_{ji} = f_{U(j)j} + x_{sj})$

f_{ik} = number of plant units established at and upstream of i where $k = D(i)$.

6. The water used by facilities sited along a river basin does not exceed the amount of water available in the basin.

$$\sum_{g\varepsilon G} \sum_{\ell\varepsilon u(j)} w^g f_\ell^g + w^g f_j^g < A_j$$

7. Major airshed quality standards must be met including the prevention of significant deterioration to Class 1 areas.

$$\sum_{j\varepsilon J} \sum_{g\varepsilon G} \alpha_{j\;n}^{p} E_p^g \, f_j^g < S_n^p$$

8. Nonnegativity and integer requirements for all variables.

$\bar{e}_{ji} > 0$ for all j and i

$f_j^g > 0$, integer for all j and g

$x_j = 0,1$ for all j

$y_j = 0,1$ for all j

The above programming problem is a linear mixed integer model. It can be solved directly by one of two basic apporaches: (1) an integer programming approach like a branch and bound algorithm with linear programming or (2) a heuristic approach. An alternative method would be to simplify the problem by eliminating the third objective and the first term of the fourth objective, along with constraints 3 and 4 and removing the integer x_j variable from the fifth constraint. The model then would be a linear programming problem and could be solved easily for moderately large problems. The third objective that would be eliminated here minimizes the number of unrealistically small facilities from entering in the solution. Unfortunately, such small facilities would then appear

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$\overline{U}(i)$ = upstream area adjacent to area i.

$\overline{D}(i)$ = downstream area adjacent to area i.

A_i = number of plant units for which water is available in area i.

p_s = number of plant units needed for load center s.

E_i = impact associated with placing one plant unit in area i.

C_i = maximum allowable number of plant units in area i.

d_i = distance from the fuel source to area i.

w_1 = weight attached to the goal of minimizing environmental impact.

w_2 = weight attached to the goal of minimizing ton miles of coal hauled.

w_3 = weight attached to the goal of minimizing transmission distances.

The MACRONET model selects locations of plant units to serve load centers such that three objectives are simultaneously optimized according to their relative weights. The three objectives are: (1) minimize overall impact of the sites chosen, (2) minimize ton-miles associated with supplying fuel, and (3) minimize megawatt-miles of transmission to the load centers. The problem is cast as a network model.

A two load center network is given in Fig. 4. The advantage of using the network structure is that the problem can be solved by an efficient flow algorithm instead of a more general linear programming routine. The main disadvantage of using the network version is that constraints on air quality cannot be easily included.

Another approach to solving the multiple load center, water resource constrained siting problem is to start with an arbitrary allocation of p_s plant units among the areas; i.e., arbitrarily set x_{si} variables at

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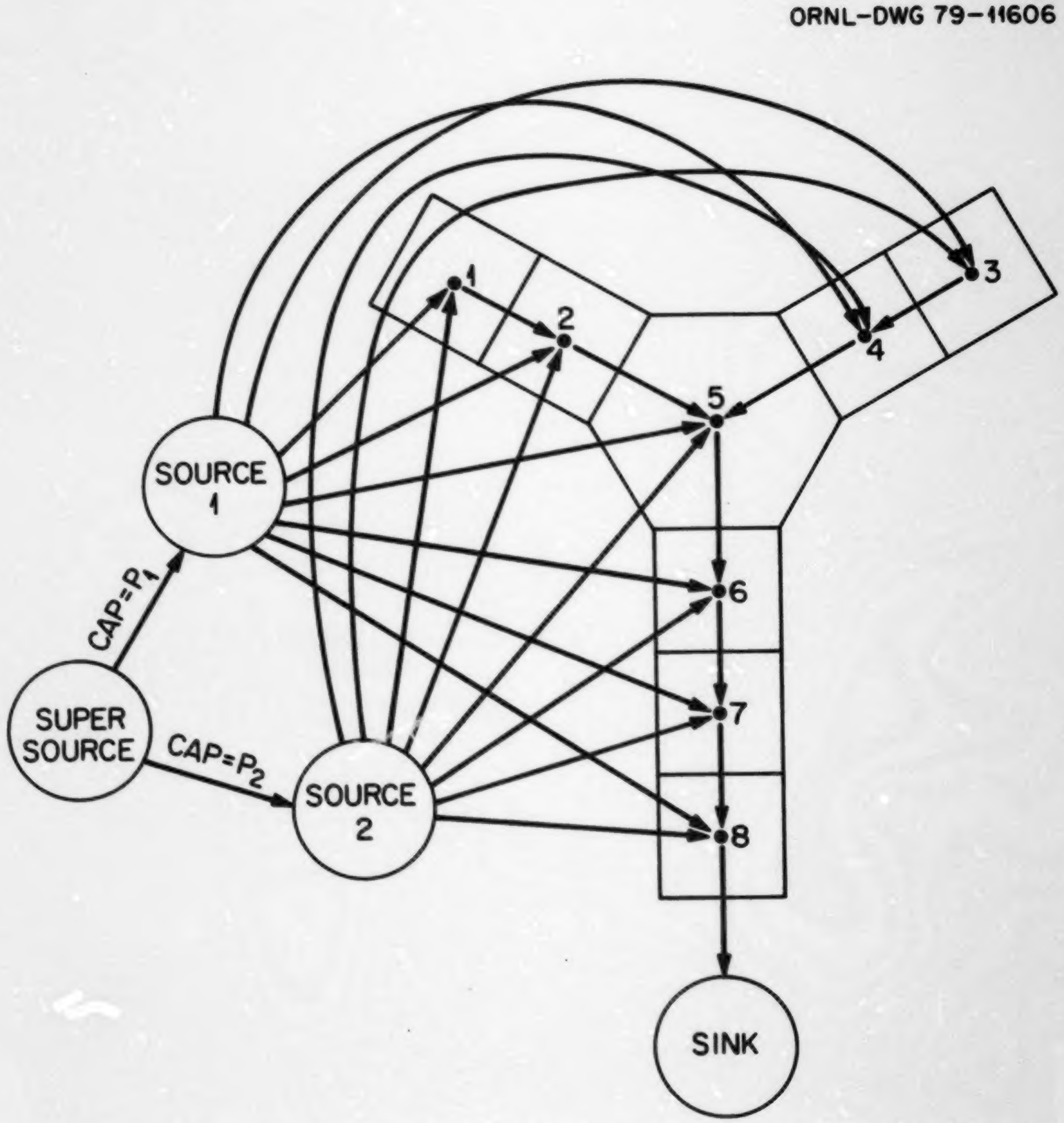
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1
2
3
4
5
6
7
8
SOURCE 1
SOURCE 2
SUPER SOURCE
CAP=P₁
CAP=P₂
SINK

Fig. 4. Structure of MACRONET 1 model for two load centers.

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integer values such that $\sum x_{si} = p_s$ for each load center S. Although this allocation probably does not meet the water resource constraints, we can use it as a starting point. Next define the violation, v_i, of each water resource constraint as:

$$\sum_{j \varepsilon U(i)} x_{sj} + x_{si} = A_i + v_i + \sum_{j \varepsilon U(i)} v_j$$

where v_i is the smallest nonnegative value such that the inequality holds. The sum of the violations, $\underline{V} = \sum_i v_i$, indicates the sum of the shortfalls in each area. Then the objective function value for this initial starting configuration is computed as:

$$\sum_s \sum_i (w_1 E_i + w_2 d_i + w_3 t_{si}) \, x_{si} + w_4 \underline{V}$$

where w_4 is the weight attached to the water resource violations $\underline{V}$. Next, we can consider area i* that has no allocation or an allocation strictly less than C_{i*}. The selected area will be a candidate for an additional plant unit. Since we are considering the placement of an additional plant unit in area i*, we will be eliminating a plant unit allocated elsewhere. It is easy to determine the objective function value for each possible exchange pair (eliminate an allocation at some point, allocate an additional unit to area i*). Since there are $\sum_s p_s$ plant units, there are $\sum_s p_s$ exchange pairs. We can easily identify the exchange pair with the lowest associated objective function value. If this value is lower than the objective function value for the current configuration allocation, then we can make an exchange with an overall improvement. Otherwise, an exchange associated with allocating a unit

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to area i* and eliminating a unit elsewhere cannot be made without increasing the weighted sum of impacts, fuel haul, transmission distances, and water resource violations. If an exchange can be made with an overall improvement, we will make that exchange. Now we can select another area in which to consider the possible addition of a plant unit along with the elimination of a plant unit elsewhere, and basically repeat the process. After repeating this process for all areas that have no allocation or an allocation strictly less than their associated maximum limit, we will have completed a cycle. We will consider additional cycles until we finish a cycle for which no exchanges have been made. The process is quite flexible, and should generate very good solutions. The basic principles of this algorithm are patterned after the approach of Teitz and Bart in solving a p-median problem. Recent studies have shown that this algorithm is quite robust and, in most circumstances, generates optimal solutions (Rosing et al., 1979).

The above solution approach is quite flexible and can be modified easily to include the third objective of MACRO 1. In other words, the above heuristic can be used to solve MACRO 1, and it represents an alternative to solving the model by a branch and bound algorithm or by simplifying it to a linear programming problem.

The MACRO 2 model may be derived from MACRO 1 by embedding a transport model for coal into the model, so that availability of certain types of coal is explicitly constrained at levels of actual capacity. Additional features of MACRO 2 include siting of coal preparation facilities, limestone transport for projected fluidized bed operations, and ash disposal and transportation costs associated with limitations proposed by P.L. 94-580 (RCRA). Additional limitations will be added to handle basic transmission network capacity between regions. The second MACRO model is under development.

Q. Charles Kolstad: How do you consider the cost of the coal?

A. In terms of MACRO 1 we are specifying the coal source in advance so we are left with the transport costs and that can be adequately handled as a function of ton miles.

Q. Jerry Eyster: How far into the future is this aiming at, going to 1999, the year 2000?

A. Ed Hillsman: This work is being funded out of the Office of Technology Impacts of DOE. Most of the work that they have been asking us to do has gone out to 1995 and I suspect ultimately to 2000.

Q. Lloyd Bender: I'm interested in that impact index. Could you briefly describe how that's constructed?

A. Oak Ridge has been using a base line siting model called ORSAM. This model tries to identify what county is a good candidate for a new facility. This particular model is based upon several criteria. ORSAM developes suitability scores for each county based on these criteria. Suitability scores include whether there's an available water supply for up to 4000 megawatts in a county, whether there is an appropriate rail line or barge line into the county or if it's in the Appalachian area, perhaps short-haul trucking. It also includes the aspect of overall environmental impacts associated with that county. At this moment, we plan to use the information generated by ORSAM.

Q. Lloyd Bender: They are essentially the criteria that engineers take into account in siting a plant, principally physical criteria?

A. As an example, scores are developed for both nuclear and fossil-fuel. If a county has any seismic activity, then that county would be excluded by giving that county a low score. The I_j scores will be based on the type of unit as well as the county. In addition to that, the scores will have certain exclusionary aspects just like Teknekron's score. If Teknekron has analyzed a county estimate that is not suitable because of some criterion then they give a weight of zero. Otherwise if there is a positive weight, the county is suitable and the larger the number is the more suitable the county.

Q. Jerry Eyster: Aren't you implicitly making the trade-off on physical units by the weights that are assigned?

A. Mr. Church: A distinction should be made between methods that lead to the determination of preferences before you run a model and methods that are not based on needing preferences before the model is solved. For the latter, one can vary the weights and solve a series of problems. By doing this, the noninferior solutions that represent the trade-off curve can be found. This is called a weighting method. With the trade-off curve a decision maker can now analyze how close to both goals he can get as well as identify what he thinks is the best solution. This is what I am proposing. Only after the trade-off curve has been developed and the decision maker has made his choice can the weights of the optimal choice — the trade-off between units — be determined.

Q. Jerry Eyster: So in essence what you are doing is changing weights to straighten out that curve.

A. Mr. Church: No, this is really a vector optimization problem where I do not know the decision maker's weights in advance. The weights are used in the weighting method in order to determine the trade-off curve.

Q. Chuck Macal: How do you present this kind of information to a decision maker? It's a multiple-dimension problem in some of the things that I have done.

A. That's a very good point. It is nice to end up with a problem with three objectives because you can easily draw a surface with a computer-graphics package and you can show the surface to a decision maker. I think it's very easy to explain and arrive at a good solution with three objectives. When you go to four objectives you go beyond what you can easily plot. One way of presenting such multidimensional data is to use value paths. Value paths have been used by researchers in water resources (Bishop) and location (Schilling).

I have found out that many problems appear to be characterized by three objectives. To find more than three objectives, you may be scratching for extra information that really perhaps isn't there.

Q. Chuck Macal: But three objectives are at least better than one.

A. I would like to think so.

Q. Verne Loose: You mentioned that — I think you said power plant siting is a public sector problem.

A. I'm posing this problem as a quasi-public problem where a strong regional planning commission would exert an influence.

C. Charles Kolstad: The problem with linear programming isn't having small capacities because that can be handled as a constraint as a matter of having units, e.g., multiples of 500 megawatts.

Q. Rick Church questions Charles Kolstad's comment: How would you get rid of the small values?

A. Charles Kolstad: I would say all capacities in a county must be greater than or equal to some minimum level.

C. Rick Church: This is an important point. What happens if one constrains the amount generated in county j to be greater than or equal to a minimum value? Then, the only solution to your LP will be that you have to place at least that capacity in each county for which you write a constraint. The only way you can get rid of that particular possibility is to introduce a zero-one variable and create a mixed integer programming problem.

Q. Verne Loose: Does your objective three quarantee that you in fact won't have this fractional plant siting?

A. Yes.

SCOAL ROUTE MODELS

In analyzing problems of coal transportation, it is necessary to identify the appropriate route that would be used in transporting a bulk commodity from a known source to a fixed destination. There are two basic route models in SCOAL. The first model seeks the route between the source and destination along a rail network when both the source and destination are served by the same railroad company. This model is essentially a shortest path problem except that certain factors are introduced to keep the route on railroad mainlines whenever possible. The second model is associated with identifying the best route from a source to a destination when transfers between one or more railroad companies are necessary. The major idea is to keep the transfers to a minimum and to keep freight on the originating line as long as possible within justifiable limits. This model is structured as a two-staged problem, and it also can be solved by a shortest path algorithm. The two model formulations are given here along with definitions of the notation used.

If the destination is on the same railroad company's tracks as the source, then the following shortest path problem can be solved:

$$\text{RM1:}\quad \text{Min } Z = \sum_{(i,j)\ \varepsilon A^R} x_{ij}^R \, d_{ij}^R \, p_{ij}^R$$

$$\text{S.T. (1)} \quad \sum_{\substack{\text{for all } j \\ (z,j)\ \varepsilon A^R}} x_{zj}^R = 1 \text{ for known source } z$$

$$\text{(2)} \quad \sum_{\substack{\text{for all } k \\ \text{where} \\ (i,k)\ \varepsilon A^R}} x_{ik}^R - \sum_{\substack{\text{for all } k \\ \text{where} \\ (k,j)\ \varepsilon A^R}} x_{kj}^R = 0 \text{ for each intermediate node } k$$

$$\text{(3)} \quad \sum_{\substack{\text{for all } i \\ \text{where} \\ (i,\ell)\ \varepsilon A^R}} = 1 \text{ for known destination } \ell$$

where

A^R = The set of arcs in railroad R.

z = known source

ℓ = known destination

d_{ij}^R = distance of arc (i,j) in railroad R

$$p_{ij}^R = \left\{ \begin{array}{l} 1.0 \text{ if link } (i,j) \text{ is CLASS A mainline} \\ 1.1 \text{ if link } (i,j) \text{ is CLASS B mainline} \\ 1.7 \text{ if link } (i,j) \text{ is CLASS A branchline} \\ 3.0 \text{ if link } (i,j) \text{ is CLASS B branchline} \end{array} \right\}$$

$$x_{ij}^R = \left\{ \begin{array}{l} 1 \text{ if link } (i,j) \text{ is used in route} \\ 0 \text{ if link } (i,j) \text{ is not used in route} \end{array} \right\}$$

The objective function of this shortest path problem contains factors that are associated with keeping the path on the mainline whenever possible. The objective function value is not the real distance of a route unless the complete route contains links that are only CLASS A, mainline. Once a route has been determined, the actual distance along it must be calculated by summing the distances of the links that it contains.

RM1 can be easily solved by a labelling technique like that of Dijkstra (1959). This is done by multiplying each arc by the appropriate p_{ij}^{R} factor and applying a labelling shortest path algorithm to the modified network. Again, once the route is identified the real distance must be recalculated.

If the destination is not on the same railroad company's tracks as the source, then following two problems must be solved:

A) The first problem is to determine the smallest number of transfers necessary to travel from an originating railroad to any intermediate railroads as well as the destination railroad (Fig. 5). The formulation is as follows:

FS

$$\text{RM2:}\quad \text{Min } F^{r} = \sum_{(m,n)\varepsilon\Psi} y_{mn}$$

$$\text{S.T. (1)}\quad \sum_{\substack{\text{for all } m\\ \text{where}\\ (s,m)\varepsilon\Psi}} y_{sm} = 1$$

$$\text{(2)}\quad \sum_{\substack{\text{for all } m\\ \text{where}\\ (m,k)\varepsilon\Psi}} y_{mk} - \sum_{\substack{\text{for all } m\\ \text{where}\\ (k,m)\varepsilon\Psi}} y_{km} = 0$$

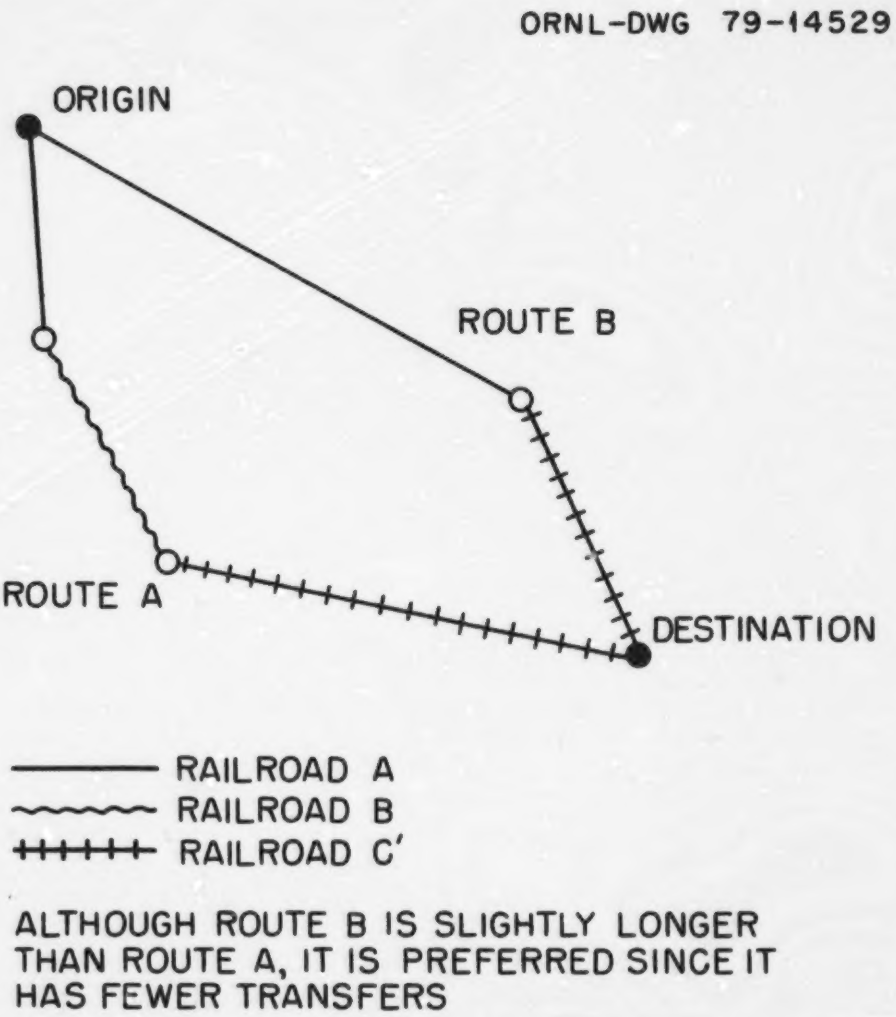
ORNL-DWG 79-14529
ORIGIN
ROUTE B
ROUTE A
DESTINATION
RAILROAD A
RAILROAD B
RAILROAD C'
ALTHOUGH ROUTE B IS SLIGHTLY LONGER THAN ROUTE A, IT IS PREFERRED SINCE IT HAS FEWER TRANSFERS

Fig. 5. Effect of number of interline transfers on route choice.

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$$(3) \quad \sum_{\substack{\text{for all } m\\ \text{where}\\ (m,r)\varepsilon\Psi}} y_{mr} = 1$$

where

$$Y_{mn} = \begin{Bmatrix} 1 \text{ if transfer between railroad } m \text{ and } n \text{ is used} \\ 0 \text{ if not} \end{Bmatrix}$$

$$\Psi = \begin{Bmatrix} (m,n) \mid \text{railroad } m \text{ and railroad } n \text{ have a transfer point} \\ \text{in common} \end{Bmatrix}$$

r = destination railroad

s = originating railroad

F^r = the minimum number of transfers necessary in travelling to railroad r from railroad s.

The above problem is associated with a network where each node represents a railroad and each arc represents a possible transfer between railroads. The length of each arc is one, so a path from any railroad s to any railroad r would have a length equal to the number of transfers. Since we are trying to find the shortest path between a given pair of railroads, we will find the path associated with the least number of transfers. The above problem can be easily solved by a shortest path labelling algorithm.

B) The second problem is to determine a route which simultaneously uses a minimum of transfers and has the following properties: the originating railroad uses the best route to each transfer point and chooses the transfer point that allows it to retain the traffic as long as possible, within justifiable limits (Fig. 6). For the second railroad, the route is the best between transfer points but represents the route that keeps the traffic on the railroad's bed as long as possible within justifiable limits, and so on. This problem can be formulated as:

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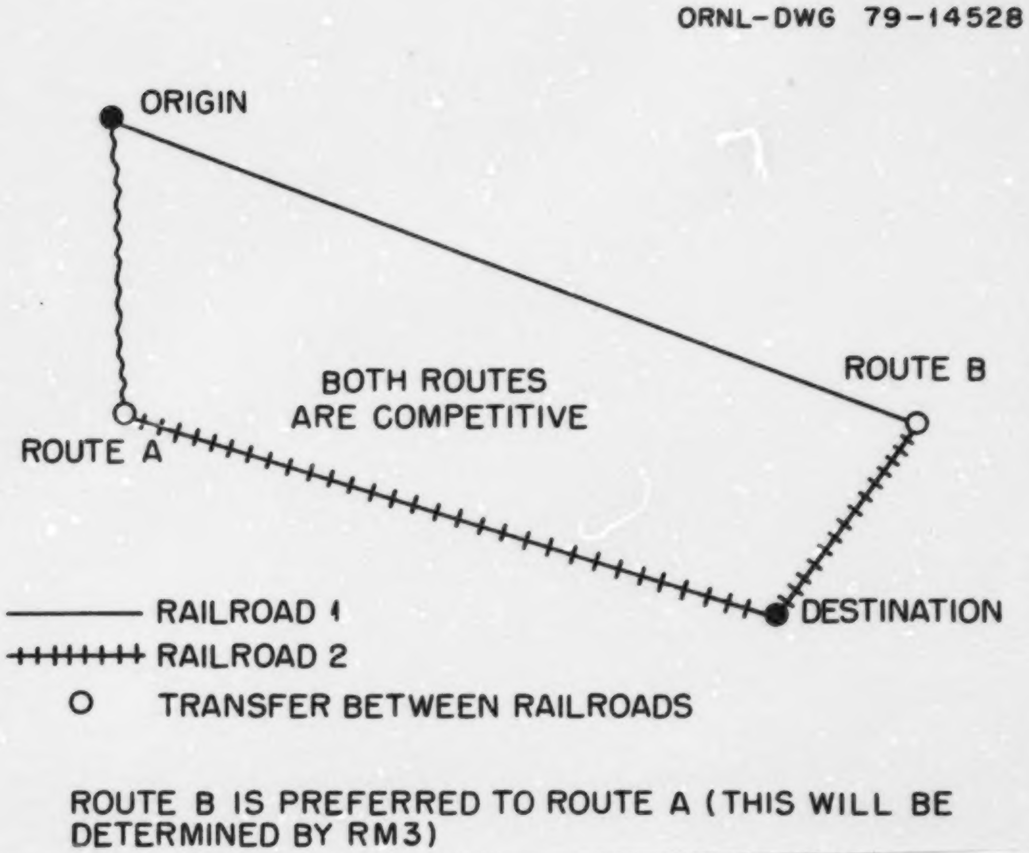
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ORIGIN
BOTH ROUTES ARE COMPETITIVE
ROUTE B
ROUTE A
DESTINATION
RAILROAD 1
RAILROAD 2
TRANSFER BETWEEN RAILROADS
ROUTE B IS PREFERRED TO ROUTE A (THIS WILL BE DETERMINED BY RM3)

Fig. 6. Longhaul advantage to railroad initiating a shipment.

$$\text{RM3:}\quad \text{Min } Z = w_1 \sum_{m\epsilon M}\left(\sum_{j\epsilon T_m} (1 + \Delta F^m) x^m_{ij} \bar{d}^m_{ij}\right) + w_2\left(\left(\sum_{m\epsilon M} \sum_{i\epsilon T_m} \sum_{j\epsilon T_m} x^m_{ij}\right) - 1\right)$$

$$\text{S.T.}\quad (1)\quad \sum_{j\epsilon T_s} x^s_{zj} = 1$$

$$(2)\quad \sum_{m\epsilon N(k)}\left(\sum_{i\epsilon T_m} x^m_{ik}\right) - \sum_{m\epsilon N(k)}\left(\sum_{j\epsilon T_m} x^m_{kj}\right) = 0 \text{ for all transfer nodes } k$$

$$(3)\quad \sum_{i\epsilon T_t} x^t_{i\ell} = 1$$

$$(4)\quad X^m_{ik} = 0,1 \text{ for all routes on all railroads}$$

where

w_1 = the weight given to minimizing the length of the route

w_2 = the weight given to minimizing the number of transfers in the route.

Δ = a constant greater than or equal to one

$\bar{d}^m_{ij}$ = shortest route on railroad m from transfer point i to transfer point j where $(i,j)\epsilon T_m$. This route can be identified by solving problem RM1.

T_m = the set of transfer points on railroad m.

$$x^m_{ij} = \left\{\begin{array}{l} 1 \text{ if the route from transfer point } i \text{ to transfer point } j \\ \quad \text{is used in railroad } m, \text{ where } (i,j)\epsilon T_m \\ 0 \text{ if not} \end{array}\right\}$$

s = index of originating railroad

t = index of terminating railroad

$\bar{d}^s_{zj}$ = shortest route on originating railroad from source z to transfer point j, where $j\ \epsilon T_s$

$\bar{d}^t_{i\ell}$ = shortest route on terminating railroad from transfer point i to terminating node ℓ, where $i\ \epsilon T_t$

transfers to a minimum so that the smallest possible number of interchanges is made.

This second model can be easily solved by using a shortest path algorithm applied to a rail network that has been modified two different ways. The first modification is to insert arcs between any possible transfer with a cost of w_2. The second modification is to take each of the original links and multiply it by the priority factor p_{ij} and the weight w_1 as well as by $(1 + \Delta F^m)$ where m represents the railroad the link is in the F^m is the smallest number of transfers necessary to travel to railroad m from the originating railroad. This factor makes longer paths on the originating railroad more competitive, thereby encouraging the shipment to remain on that line as long as possible within justifiable limits.

SCOAL TRANSPORT MODELS

Beyond identifying a route that is used between a given destination and source, it is important to analyze the total transportation pattern between coal sources and destinations. Five transport models are being developed for the SCOAL system. The SCOAL transport models may be used to analyze regional patterns of shipments under several different assumptions and scales. At this time the individual models are designed either to look at efficient transportation patterns or to identify problems in coal tranpsort on a rail network (e.g., exceeding track capacity). Currently, all five of the models assume that track capacity is fixed and that only a certain proportion is available for coal

F^m = the smallest number of transfers necessary to reach railroad m from originating railroad s (obtained from problem RM2)

$$x^s_{zj} = \begin{cases} 1 & \text{if the route between source } z \text{ and transfer point } j \text{ is used on the originating railroad, where } j \in T_s \\ 0 & \text{if not} \end{cases}$$

$$x^t_{i\ell} = \begin{cases} 1 & \text{if the route between transfer point } i \text{ and final destination } \ell \text{ is used on the terminal railroad, where } \ell \in T_t \\ 0 & \text{if not} \end{cases}$$

M = the set of railroads

N(k) = set of railroads that have node k as a transfer point

This problem is also a modified shortest path problem in that the constraint set requires that a unit flow be routed through a network starting from the source and ending at the destination. The model is based on routes between transfer points on a given railroad. These can be determined by solving problem RM1 between all pairs of transfer points on that railroad. This can be easily accomplished by Floyd's algorithm (1962). Given the best route between any pair of transfer points connected by a railroad, the problem then becomes one of selecting the transfer points and the connecting routes at a point which allows them the most justifiable return. This feature is included by systematically making routes on successive railroads numerically larger in order to make a more lengthy route on the originating line justifiable and competitive. The shortest route on a railroad between transfer points is always taken, but the point of transfer, and the railroad chosen for the transfer, may bring greater return to the originating railroad without significantly adding to the cost of the overall route. This is also done whenever possible for other railroads handling the same shipment. The second term of the objective function is associted with keeping the transport purposes. In addition, no capacity expansion capability has been developed. However, future modeling work will develop a regional track management simulation model directed at determining better estimates of capacity, competing needs for rail services, and optimal track investment strategies.

The first transport model is a simple transportation problem that minimizes the total ton-miles of haul associated with supplying specified needs from sources with known capacity (Fig. 7). This problem is simple and relatively easy to solve and can be set up with only a small amount of data. However, it is only able to estimate efficient matching of sources and destinations and a lower bound on the total ton-miles of haul necessary in a region. It can not indicate where track capacity would be exceeded, or incorporate known source-destination interactions fixed by long-term supply constracts. The first model can be written as:

F7

$$\text{CTM1:} \quad \text{Min } Z = \sum_{k \epsilon K} \sum_{j \epsilon J} X_{kj} \, d_{kj}$$

$$\text{S.T. (1)} \quad \sum_{j \epsilon J} X_{kj} \leq S_k \text{ for all sources}$$

$$\text{(2)} \quad \sum_{k \epsilon K} X_{kj} \geq H_j \text{ for all destinations}$$

where

X_{kj} = amount of coal transported from coal source k to power plant j during planning period.

S_k = the amount of coal available at coal source k during planning period.

H_j = tons of coal needed at facility j during planning period.

d_{kj} = distance from coal source k to facility j.

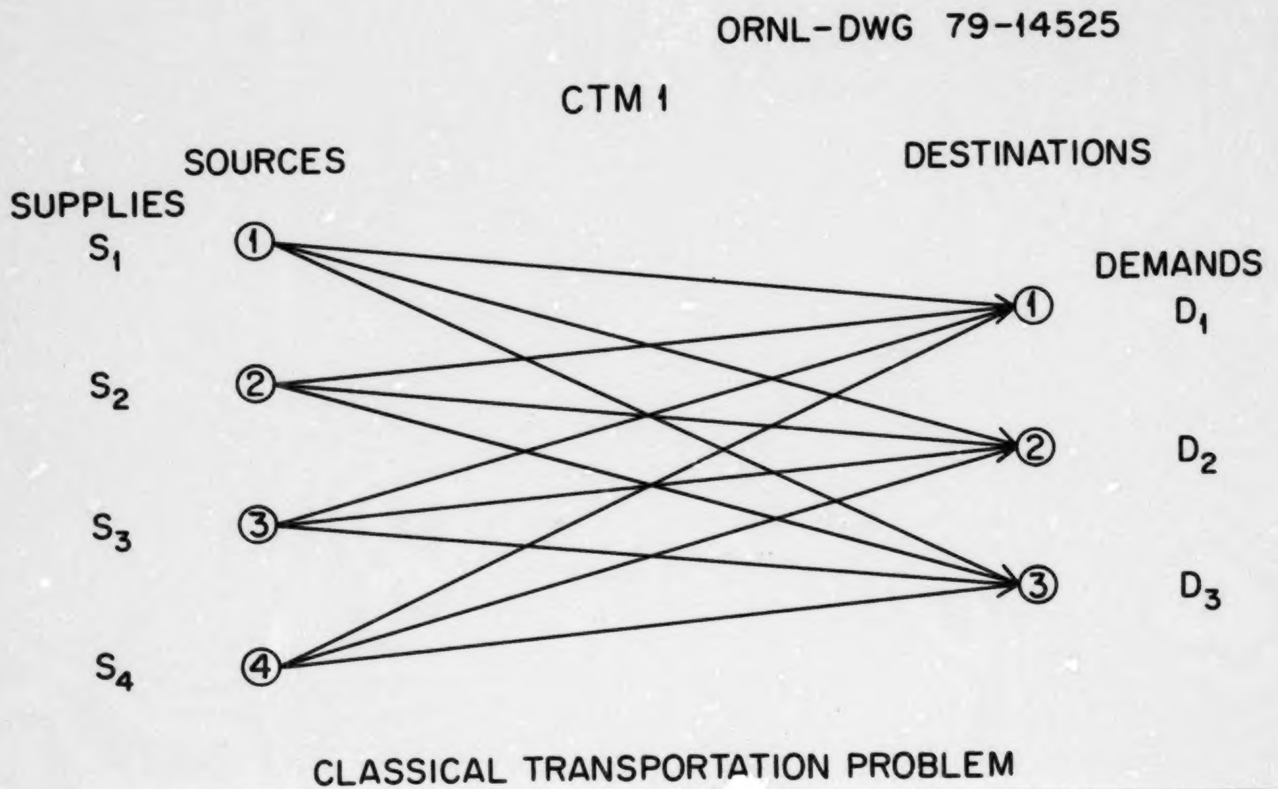

ORNL-DWG 79-14525
CTM 1
SOURCES
SUPPLIES
S_1
S_2
S_3
S_4
①
②
③
④
DESTINATIONS
DEMANDS
①
②
③
D_1
D_2
D_3
CLASSICAL TRANSPORTATION PROBLEM

Fig. 7. Coal transport model #1, considering ton-miles only.

The second coal transport model extends the first by considering the properties of different types of coal. The second model has the same objective as the first except that the total transport can be disaggregated into the ton miles of haul associated with each coal type (Fig. 8). The constraints set three types of requirements. The first type ensures that no source can supply more coal of a given type than its established or forecasted capacity will permit. The second type of constraint insures that the total heat value associated with the coal shipped to a given demand equals the requirement at that demand. The third type maintains an upper limit on the sulfur content of the coal delivered to meet each demand. This upper limit (or range if necessary) can be estimated based on regulations for low sulfur content, control equipment, other emission regulations, and/or other factors. This model is structured as a linear programming problem and can be solved easily for a large number of sources and destinations. The formulation is as follows:

F8

$$\text{CTM2:} \quad \text{Min } Z = \sum_{q \varepsilon Q} \sum_{k \varepsilon K} \sum_{j \varepsilon J} X_{kj}^{q} \, d_{kj}$$

$$\text{S.T.} \quad (1) \quad \sum_{j \varepsilon J} X_{kj}^{q} \leq S_{k}^{q} \text{ for all } q \text{ and all } k \varepsilon T(q)$$

$$(2) \quad \sum_{k \varepsilon K} \left(\sum_{q \varepsilon Q} \theta_{q}^{1} \, X_{kj}^{q} \right) \geq H_{j} \text{ for all } j$$

$$(3) \quad \sum_{k \varepsilon K} \sum_{q \varepsilon Q} \theta_{q}^{2} \, X_{kj}^{q} \leq SC_{j} \text{ for all } j$$

$$(4) \quad X_{kj}^{q} \geq 0$$

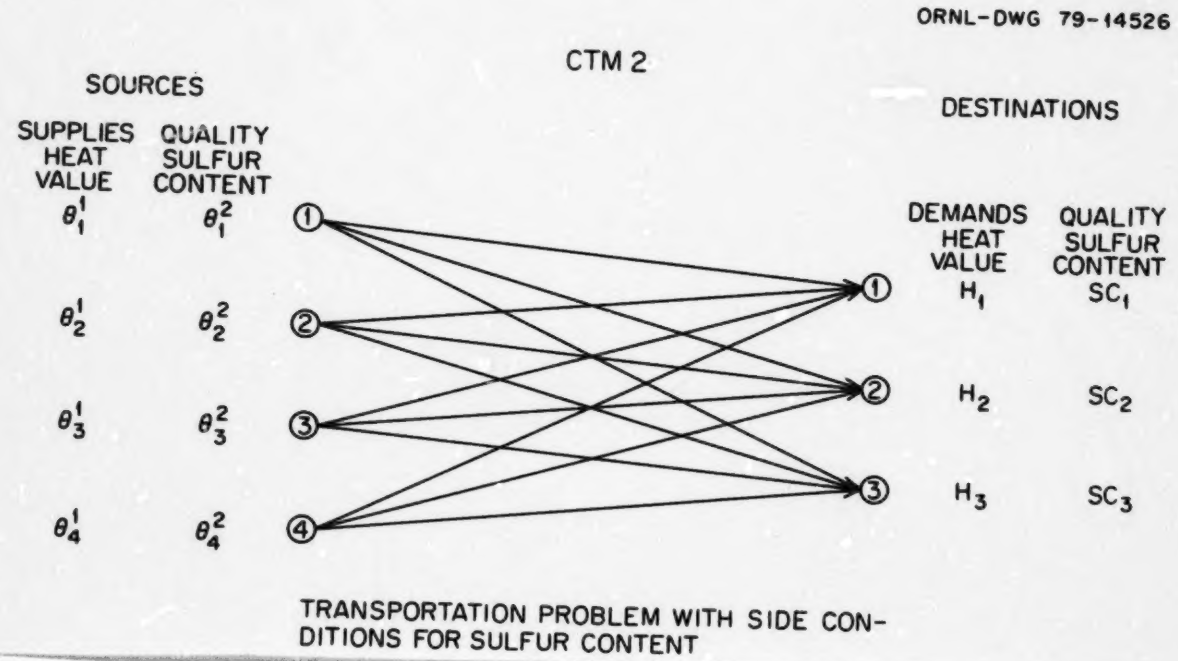

ORNL-DWG 79-14526
CTM 2
SOURCES
SUPPLIES HEAT VALUE
QUALITY SULFUR CONTENT
θ_1^1
θ_1^2
θ_2^1
θ_2^2
θ_3^1
θ_3^2
θ_4^1
θ_4^2
①
②
③
④
DESTINATIONS
DEMANDS HEAT VALUE
QUALITY SULFUR CONTENT
①
②
③
H_1
SC_1
H_2
SC_2
H_3
SC_3
TRANSPORTATION PROBLEM WITH SIDE CONDITIONS FOR SULFUR CONTENT

Fig. 8. Coal transport model #2, considering coal quality and ton-miles.

where

K = set of coal sources

J = set of power facilities

$T(q)$ = set of sources having coal type q

X^q_{kj} = the amount of coal type q transported from coal source k to power facility j during planning period (sources may include coal preparation centers)

θ^1_q = the heat content of coal type q per unit amount

θ^2_q = the sulfur content of coal type q per unit amount

H_j = heat requirement at facility j

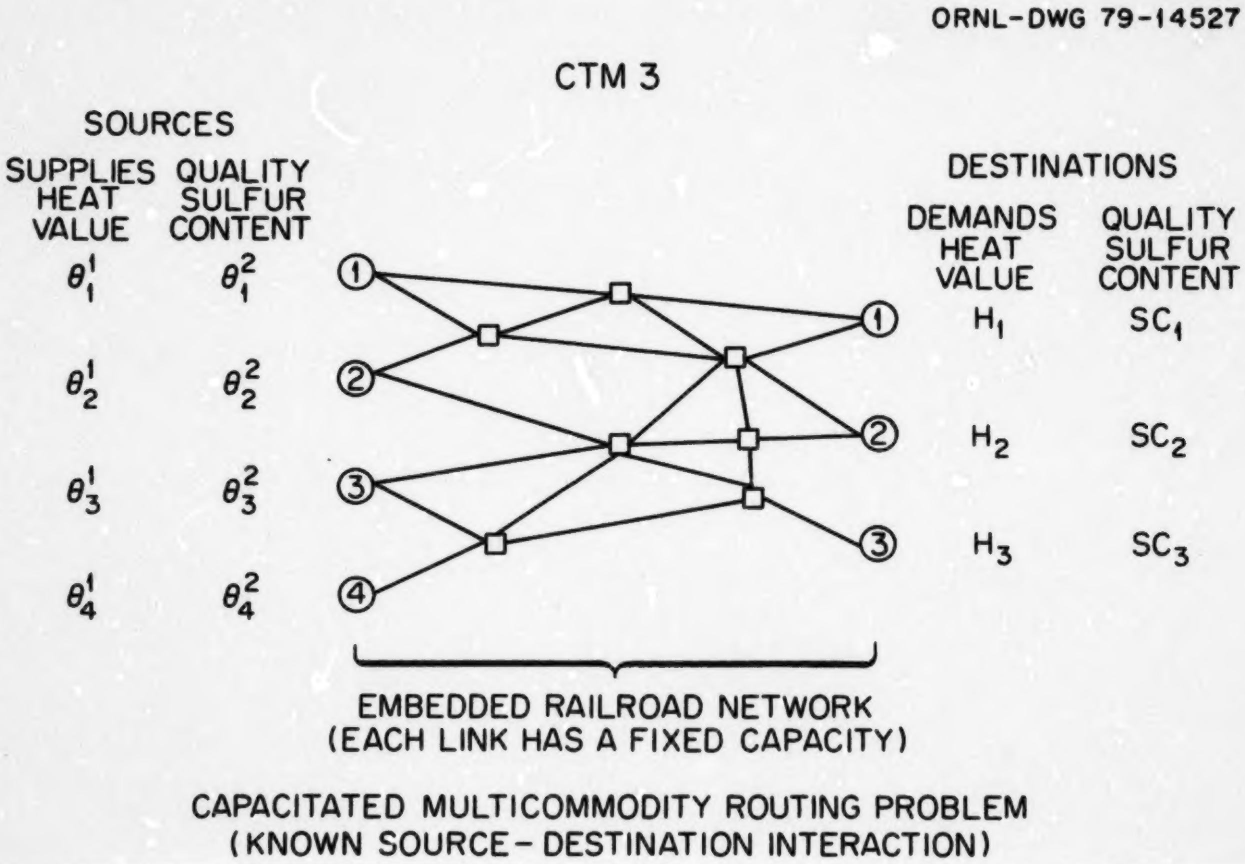
S^q_k = availability of coal type q at source k during planning period

d_{kj} = distance from source k to facility at j

SC_j = maximum sulfur content of fuel brought to site j

The third coal transport model is an extension of CTM2. Like CTM2, this model meets the separate requirements of each demand area for total heat value and sulfur content. The amount of each coal type that is transported from a given supply area is limited by the capacity of that area to supply that type of coal. The major extension of CTM2 is the fact that this third model has an embedded rail network (Fig. 9). The amount of coal transported over each link in the embedded network is limited to the total capacity of that link less the amount of capacity used in transporting other commodities. The objective is again to minimize the total ton-miles of transport. The model is cast as a linear program and, because of the large number of variables and constraints, it will only be able to handle a regional rather than a national problem. The CTM3 model is formulated as:

F9



ORNL-DWG 79-14527
CTM 3
SOURCES
SUPPLIES HEAT VALUE
QUALITY SULFUR CONTENT
θ_1^1
θ_1^2
θ_2^1
θ_2^2
θ_3^1
θ_3^2
θ_4^1
θ_4^2
①
②
③
④
DESTINATIONS
DEMANDS HEAT VALUE
QUALITY SULFUR CONTENT
①
②
③
H_1
SC_1
H_2
SC_2
H_3
SC_3
EMBEDDED RAILROAD NETWORK
(EACH LINK HAS A FIXED CAPACITY)
CAPACITATED MULTICOMMODITY ROUTING PROBLEM
(KNOWN SOURCE - DESTINATION INTERACTION)

Fig. 9. Coal transport model #3, considering coal type, ton-miles, and structure of transportation network.

$$\text{CTM3:}\quad \text{Min } Z = \sum_{q \varepsilon Q} \sum_{(1,\ell)\varepsilon A} X^{q}_{i\,\ell}\, d_{i\,\ell}$$

$$\text{S.T. (1)}\quad \sum_{(\Gamma(k),\ell)\varepsilon A} X^{q}_{\Gamma(k),\ell} < S^{q}_{k} \text{ for all sources } k \varepsilon K$$

$$\text{(2)}\quad \sum_{(i,z)\varepsilon A} X^{q}_{i\,z} - \sum_{(z,\ell)\varepsilon A} X^{q}_{z\,\ell} = 0 \text{ for all } z \text{ where } z \neq T(j),\ z \neq \Gamma(k)$$

$$\text{(3)}\quad \sum_{(i,T(j))\varepsilon A} \theta^{1}_{q} X^{q}_{i,T(j)} \geqslant H_{j} \text{ for all } j \varepsilon J$$

$$\text{(4)}\quad \sum_{(i,T(j))\varepsilon A} \theta^{2}_{q} X^{q}_{i,T(j)} \leqslant SC_{j} \text{ for all } j \varepsilon J$$

$$\text{(5)}\quad \sum_{q} X^{q}_{i\,\ell} \leqslant C_{i\,\ell} \text{ for all } (i,\ell)\varepsilon A$$

$$\text{(6)}\quad X^{q}_{i\,\ell} \geqslant 0 \text{ for all arcs } (i,\ell)\varepsilon A \text{ and } q \varepsilon Q$$

where

Q = set of all coal types

J = set of power plants

K = set of coal sources

A = set of arcs (i,ℓ) in rail network

$\Gamma(k)$ = the node in the rail network closest to source k

$T(j)$ = the node in the rail network closest to power facility j

$X^{q}_{i\,\ell}$ = amount of coal type q transported on link (i,ℓ) during the planning period

S^{q}_{k} = availability of coal type q at source k during the planning period

$C_{i\,\ell}$ = capacity of rail link (i,ℓ) during planning period

$d_{i\ell}$ = distance of rail link (i,ℓ)

θ_q^1 = the heat content of coal type q per unit amount

θ_q^2 = the sulfur content of coal type q per unit amount

SC_j = maximum sulfur content of fuel brought to site j

H_j = heat requirement at site j

The fourth and fifth coal transport models represent a wide departure from the previous three models. The CTM1, CTM2, and CTM3 models actually select the pairings of sources and destinations, according to the objective of minimizing ton-miles of haul. For CTM4 and CTM5, the pairings of sources and destinations are specified in advance, and the models select the route connecting each pair. In many cases, long term contracts are arranged for supplying coal to a given facility from a given source. Thus, there may be little flexibility in changing the source for a particular facility over the short run. Even though there may be little flexibility in changing a given source-destination pair, it is still important to determine if there will be major rail capacity problems in the future. Therefore, the CTM4 and CTM5 models are structured to preserve the known source-destination pairings but to be flexible in choosing the routes for each pair. Basically, both CTM4 and CTM5 are associated with determining whether the rail network has enough capacity such that each destination can receive its shipments from its prespecified (contractual) sources. If the rail network does have enough capacity, then both CTM4 and CTM5 models will yield a set of routes associated with minimum total transport in ton-miles.

The difference between CTM4 and CTM5 is that the CTM4 model has the flexibility to use any possible route for a given pair of source and

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estimation (Fig. 10), whereas the CTM5 model can select only from among a small set of prespecified routes for each fixed pair of source and destination (Fig. 11). The CTM4 model is based on the entire rail network and therefore is very large in the numbers of its variables and constraints. At present it appears that the CTM4 model will not be used to any great degree, for this reason. The CTM5, however, will be used because of its smaller problem size and its ability to keep track of contracted pairings. Both CTM4 and CTM5 models are given below, with their respective notation.

F10

F11

$$\text{CTM4:}\quad \text{Min } Z = \sum_{p\varepsilon P} \sum_{(i,\ell)\varepsilon A} d_{i\ell} X^p_{i\ell}$$

$$(1)\quad \sum_{\substack{\ell \\ \text{where} \\ (i,\ell)\varepsilon A}} X^p_{i\ell} = \frac{\alpha^p_j H_j}{\theta^1_i} \text{ for } i\varepsilon P \text{ and } j\varepsilon P$$

$$(2)\quad \sum_{(i,z)\varepsilon A} X^p_{iz} - \sum_{(z,j)\varepsilon A} X^p_{zj} = 0 \text{ for each intermediate rail node } z$$

$$(3)\quad \sum_{\substack{i \\ \text{where} \\ (\ell,j)\varepsilon A}} X^p_{\ell j} = \frac{\alpha^p_j H_j}{\theta^1_i} \text{ for } i\varepsilon P \text{ and } j\varepsilon P$$

$$(4)\quad \sum_p X^p_{i\ell} < C_{i\ell}$$

$$(5)\quad X^p_{i\ell} > 0$$

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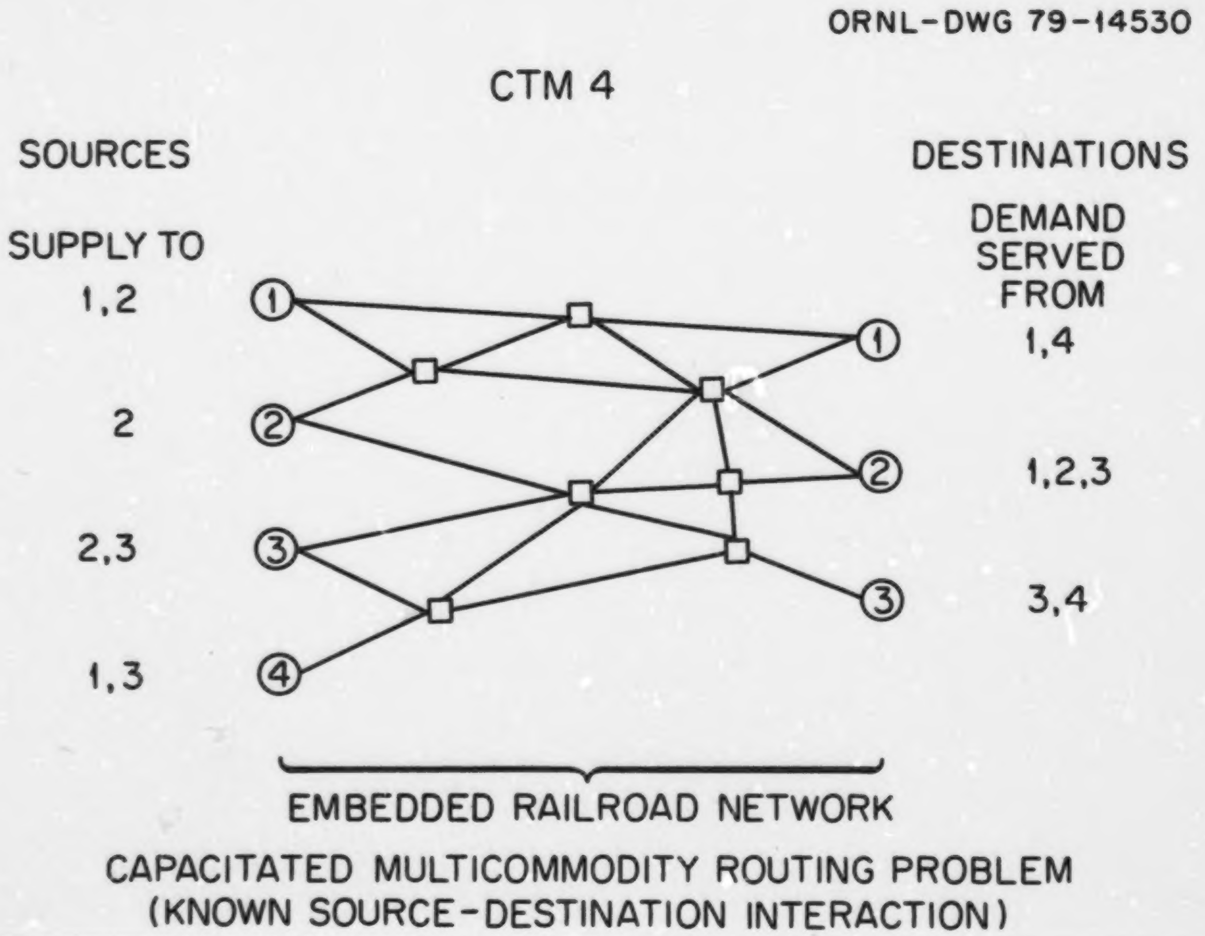
ORNL-DWG 79-14530
CTM 4
SOURCES
SUPPLY TO
1,2
2
2,3
1,3
①
②
③
④
DESTINATIONS
DEMAND
SERVED
FROM
1,4
1,2,3
3,4
①
②
③
EMBEDDED RAILROAD NETWORK
CAPACITATED MULTICOMMODITY ROUTING PROBLEM
(KNOWN SOURCE-DESTINATION INTERACTION)

Fig. 10. Coal transport model #4, with origin-destination pairs known and all routes available to connect each pair.

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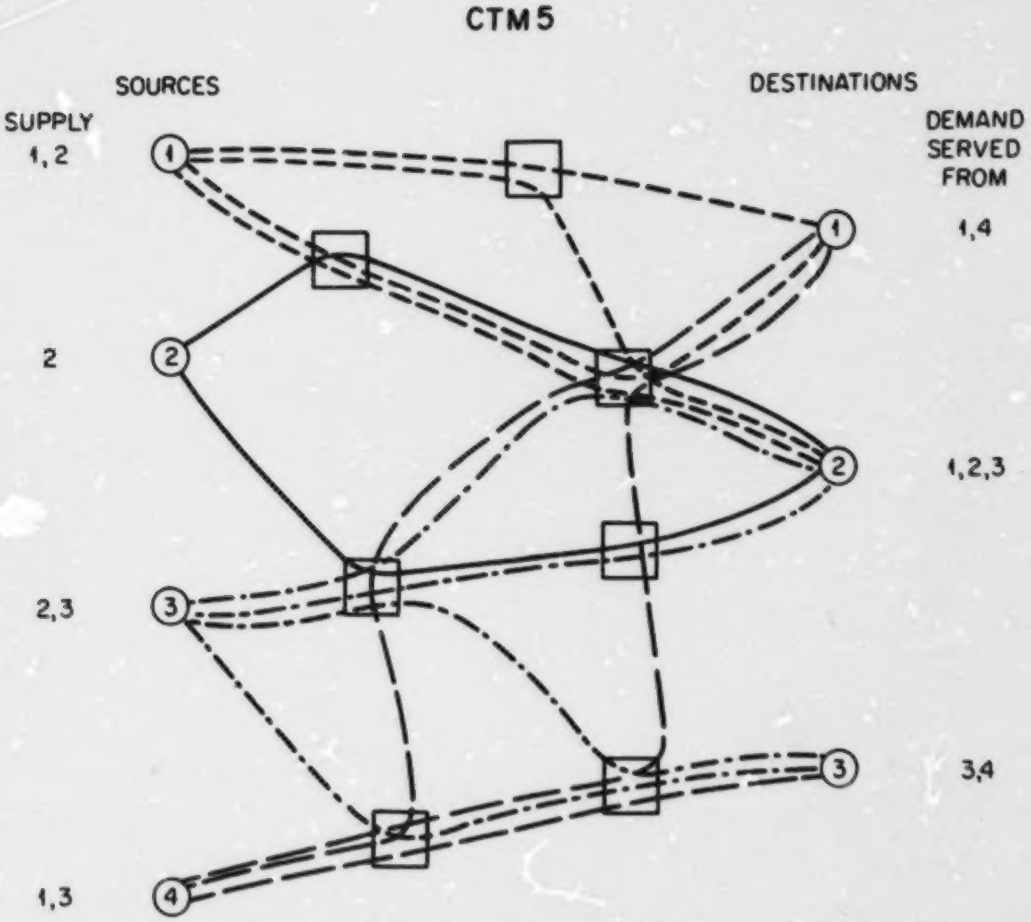
CTM5
SOURCES
DESTINATIONS
SUPPLY
DEMAND SERVED FROM
1, 2
1
2
2
2,3
3
1,3
4
1
1,4
2
1,2,3
3
3,4

MATCHING PROBLEM WITH CAPACITY CONDITIONS.

Fig. 11. Coal transport model #5, with origin-destination pairs known and routes to be selected from a previously determined subset of all possible routes.

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where

A = set of arcs (i,ℓ)

p = a known source-destination pair of coal mine and power plant

P = the set of all source-destination pairs

θ^1_i = heat value of coal from source i

H_j = heating needs at destination j

α^p_j = fraction of total coal needs satisfied by pairing p of source and destination j

$X^p_{i\ell}$ = the amount of coal shipped between source destination pair p on arc (i,ℓ)

$d_{i\ell}$ = length of arc (i,ℓ)

To derive CTM5, identify a given number (e.g., five) of major routes for each source-destination pair p. Let:

R^m_p = the m*th* major route between source-destination pair p

$D(R^m_p)$ = the distance of the m*th* route between source-destination pair p

$X(R^m_p)$ = amount of coal shipped between source-destination pair p for the m*th* route during the planning period

$T(p)$ = amount of coal needed for the p*th* pairing

$\overline{A}(i,j) = \left\{R^m_p \mid \text{arc } (i,j) \text{ is in route } R^m_p\right\}$

C_{ij} = capacity of arc (i,j) during the planning period

CTM5: $$\text{Min } Z = \sum_p \sum_m X(R^m_p)\ D(R^m_p)$$

S.T. (1) $\sum_m X(R^m_p) = T(p)$ for all source-destination pairs

(2) $\sum_{R^m_p \epsilon \overline{A}(i,j)} X(R^m_p) < C_{ij}$ for all arcs

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MAXIMUM
CENTER LINE
REMAINING LINES OF TYPE
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$$(3)\ X(R_p^m) \geq 0 \text{ for each } R_p^m$$

Several equity problems may occur in models CTM4 and CTM5. It is proposed that the following conditions be considered in the analysis of these problems.

1. Keep the amount of tonnage on routes other than the shortest route as small as possible by explicitly minimizing this quantity.
2. Limit the amount of tonnage transported on routes other than the shortest to a fixed percentage of the total shipped to a given power plant.
3. Keep the number of optional routes identified to ones where only slight additional transport costs are incurred.

Q. Andy Van Horn: How do you decide what the sulfur content is of that particular site?

A. The intent of this model is not necessarily for feeding information to the siting model. We consider it to be a stand-alone model in itself and that it can be used to analyze coal shipments — optimal patterns between sources of demands.

A. Ed Hillsman: In trying to answer this within the context of the whole system, if you can come up with a set of sulfur values and heat values from any particular source, you can run the model.

Q. Andy Van Horn: Does this model produce costs of transportation of coal in any way?

A. Mr. Church: No. This model minimizes the total ton mileage of haul of all coal given that the amount of coal available of certain types at given sources shipped away from given sources does not violate the supply during that planning period. The amount of coal that is received at a given site must meet the heating requirements at that site, and sulfur content of coal must not violate the upper limit on sulfur.

Q. Rich Bernknopf. How do you handle contractual arrangements? Different aged contracts have different time periods.

A. We want to solve the models for discrete time periods and allow certain contracts to have lives that are expended through time.

Q. Rich Bernknopf. How do spot market purchases fit into your network?

A. In terms of data I'm not sure but in terms of formulation we just add an extra set of variables to represent a spot contract.

Q. Jerry Eyster. Do you consider all commodities, not just coal?

A. Only coal at the moment. CACI has analyzed 40 commodities, 10 of which are coal. They are doing a national analysis of those 40 commodities being shipped between BEA regions. They are using rail, barge, truck, and airline networks and use an ingenious scheme to balance out the flows in the network when they have capacity problems.

SCOAL TRANSMISSION MODELS

The development of regional transmission models for the SCOAL system has just begun. Because the transmission models are to be used for regional analysis purposes, the level of detail will be less than that of the individual utility. In addition, because their purpose will be to indicate potential problems rather than to schedule day-to-day operations, the level of detail and focus will differ from that of the intertie and cooperative grids such as the PJM grid.

At this phase of development, the SCOAL system has only one transmission model (Fig. 12). This model is a multiobjective transshipment problem with losses. It seeks a set of transmission flows that both minimizes megawatt-miles of transmission and has a minimum of transmission losses. The formulation of this model is given below.

F1

$$\text{ETM1:}\quad \text{Min } Z = w_1 \sum_{(i,j)\varepsilon A} d_{ij} e_{ij}\, \alpha_{ij} + w_2 \left(\sum_{\substack{\text{for all} \\ (\ell,j)\varepsilon A \\ \text{and } \ell\ \varepsilon\ A}} e_{ij} - \sum_{k\varepsilon K} D_k \right)$$

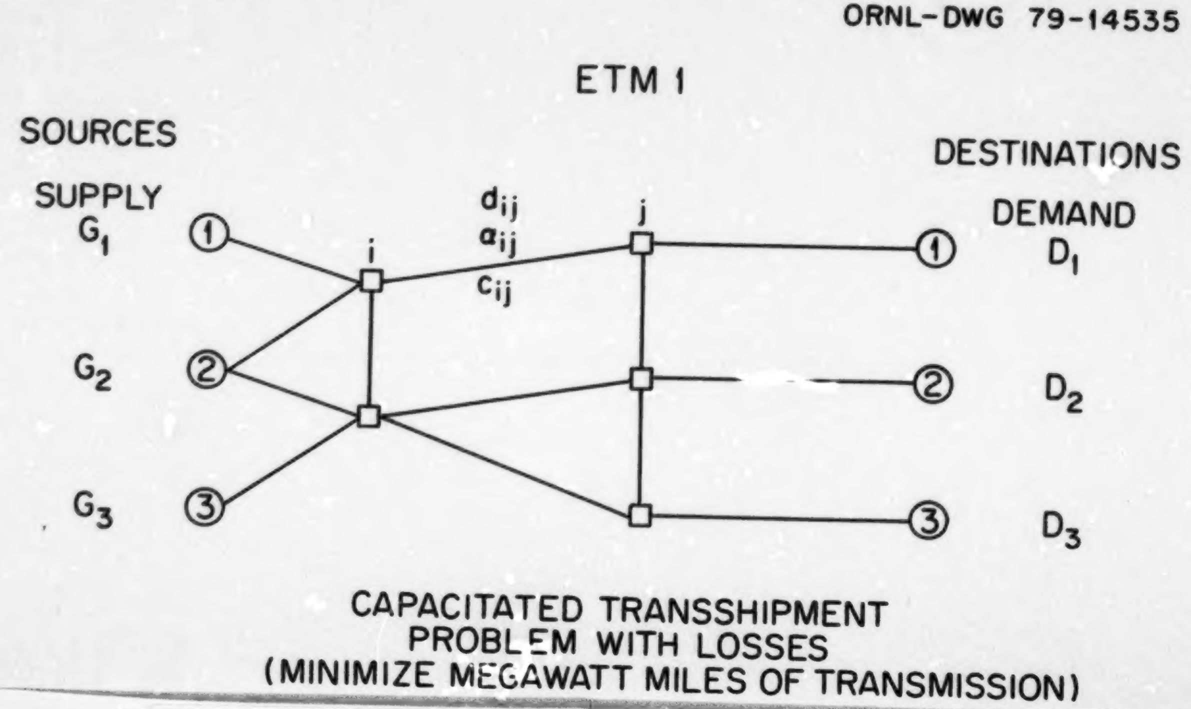
ORNL-DWG 79-14535
ETM 1
SOURCES
SUPPLY
G1
G2
G3
①
②
③
i
j
dij
aij
cij
DESTINATIONS
DEMAND
D1
D2
D3
CAPACITATED TRANSSHIPMENT
PROBLEM WITH LOSSES
(MINIMIZE MEGAWATT MILES OF TRANSMISSION)

Fig. 12. Structure of SCOAL's electric transmission model.

S.T. (1) $\sum_{(\ell,j)\epsilon A} e_{\ell\,j} < G_{\ell}$ for all ℓ

(2) $\sum_{(i,z)\epsilon A} \alpha_{iz} e_{i\,z} - \sum_{(z,j)\epsilon A} e_{z\,j} = 0$ for each intermediate position z

(3) $\sum_{(i,k)\epsilon A} \alpha_{i\,k} e_{i\,k} - \sum_{(k,j)\epsilon A} e_{k\,j} = D_k$ for $k \epsilon K$

(4) $e_{i\,j} \leqslant C_{i\,j}$ for all $(i,j)\epsilon A$

(5) $e_{i\,j} \geqslant 0$

Notation

$e_{i\,j}$ = amount of electricity entering link (i,j) at position i and being transmitted to j during planning period

α_{ij} = fraction of electricity arriving position j on link (i,j)

D_k = demand at position k on the grid

K = the set of demand positions on the grid

G_{ℓ} = maximum available amount of electricity at generation point i during planning period

A = the set of transmission links (i,j)

C_{ij} = the capacity of transmission link (i,j) during planning period

d_{ij} = distance of transmission link (i,j)

L = set of generation positions on grid

w_1 = weight attached to minimizing megawatt miles of transmission

w_2 = weight attached to minimizing power losses in transmission

The above model will be solved by linear programming. Because the development of the SCOAL transmission models is in its initial phase, the above model will probably be one of several models for transmission system analysis. Several properties which will be emphasized in further development include making inter-utility transfers only after intrautility needs have been met, and meeting inter-utility commitments first before considering any further utility sharing. Such requirements may well affect overall regional network sharing and produce constraints that will make it difficult to plan efficient routing of electricity.

EXTENSIONS TO THE SCOAL MODELS

At present the SCOAL models are structured within the context of rail transport: all of the transport and route models move coal by rail. Future extensions will integrate rail transport with shipments by barge and short truck haul. The transport models will feature transfers of mode at various positions. A component to site barge-rail terminals may also be included.

Future work on SCOAL transport models will also incorporate other large users competing for coal and for transportation services. Major industrial categories will be included to determine the effect of all coal users on transportation problems. In addition, the transportation of limestone may also be included as a further need associated with coal use by fluidized bed combustion. The inclusion of other bulk commodities such as grain will not be done in the near future, but remains a possibility.

In the siting models, major extensions will be to include other possible uses for coal, including gasification and liquifaction. Further work will be directed in developing a coal preparation siting component to the MESO model. Each of these extensions represents the demand of different uses of coal or the changing of the properties before use and/or transport.

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THE MARGINAL COST OF CONFORMING TO SULFUR EMISSION STANDARDS FOR COAL

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Reston, VA
July, 1979

I. Introduction

Federal and State regulations to control sulfur emissions at power plants have a significant effect on the amount and type of coal that can be burned by a utility. Coal resources are found in varying amounts and quality in 32 States in the United States. Coals in the western regions are of lower rank, i.e., 99 percent of the subbituminous coal and lignite (low Btu coals) are in States west of the Mississippi River. On the other hand, 83 percent of the anthracite and bituminous coals (high Btu coals) lie in the eastern regions. As a summary view, most of the unmined coal in the U.S. is overlain by 1000 or less feet of overburden, a majority of the high quality coal is in the East, and the greatest amount of strippable coal, hence coal with lowest extraction costs, is found in the West. Moreover, total U.S. production of high Btu, low sulfur (less than 1% by weight) coal, which conforms to current emission standards, is insufficient to meet current demand by electric utilities.

The purpose of this paper is to examine the incremental costs of increasing the conformance by utilities with the 1975 regional sulfur emission standards and to examine the impact on coal shipment patterns of these more restrictive sulfur emission standards at electric utilities. Using an interregional programming model of the U.S. coal industry, industry extraction patterns are analyzed subject to alternative environmental policies ranging from no sulfur emission standards to actual regional 1975 emission standard conformance plus 45 percent.

On the basis of the standards for Air Quality Control Regions (AQCR's), [1] it is estimated that 35 percent of total coal consumed in 1975 did not meet regional requirements. [2] When utilities meet the regional standards or the regulations they do so either through the use of coals with permissible sulfur levels or through the use of pollution control devices. Since sulfur emission standards vary among regions, one of the alternatives for maximizing both the utilization of coal and the attainment of environmental objectives is to transfer, or encourage the redistribution of, coal from one AQCR or use to which it is normally shipped but for which it does not meet the standards, to another area or use where it is permissible. [3]

Imposition of a sulfur restriction on a demand region could cause a significant change in the origin of the coal consumed in that AQCR or demand region. For example, prior to SIP implementation in a given region, local coal containing 4.0 percent sulfur by weight could be consumed. One scenario might be that after imposition of the standard, only 1.8 percent sulfur (by weight) coal may be consumed. Coal once locally purchased in this region must now be imported from a more distant source. The new coal delivered is more expensive because a transportation charge has been added to the delivered price at the consuming center, and the local coal may go unused. Another scenario might be to continue to utilize local coal but to install stack gas scrubbers to clean the exhaust given off at the power plant. In 1975, the year under analysis, stack gas scrubbers were available in only a very limited way. For that reason, this analysis focuses solely on the redistribution, due to 1975 sulfur standards, of unscrubbed coal.

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[1] The notion of AQCR's was established in the 1967 amendments to the Clean Air Act of 1963 (42 USC 1872 et seq.). (EPA: Federal Air Quality Control Regions, 1972). The AQCR system was conceived to manage the abatement, prevention, and control of air pollution on a regional basis. The regions are based on jurisdictional boundaries, urban-industrial concentrations, and other factors. There are 243 AQCRs for the conterminous United States. This regional classification lends itself directly to coal demand regions because both Environmental Protection Agency (EPA) and State Implementation Plan (SIP) regulations set minimum standards for point source sulfur emission.

[2] Emission standards used in this paper are based on established and proposed rules under State Implementation Plans (SIP's) for 1975 published by the Environmental Protection Agency.

[3] U.S. Bureau of Mines, Mineral Industry Survey, Assessment of the Impact of Air Quality Requirements on Coal in 1975, 1977, and 1980 January 1974, p. 3.

II. The Model

In order to compare the impact of regional sulfur regulations during 1975 several coal distribution scenarios are developed. All scenarios utilize an interregional programming model that minimizes the sum of extraction and transportation costs but varies the levels of regional conformance with air quality restrictions in coal demand regions. [4/] All scenarios employ 1975 production at supply nodes (mining regions), demand by major consuming nodes (consumption regions), and transportation rates. The model uses actual short line rail and barge distances and time in transit so that coal routes are unrestricted, i.e., no restriction forces coal to traverse historical routes. Thus, coal can be shipped from any producing region to any consuming region if it is economically efficient; that is, the sum of extraction and transportation costs is minimized permitting the firm to be indifferent as to local origin once coal quality factors are taken into account. The linear program system of equations is:

$$\text{Min } Z^* = \sum_{i=1}^{m} \sum_{j=1}^{n} \sum_{k=1}^{r} \sum_{l=1}^{2} (c_{il} + t_{ijk})\, x_{ijkl} \qquad (1)$$

$$\text{Subject to: } \sum_{i=1}^{m} \sum_{j=1}^{n} \sum_{k=1}^{r} \sum_{l=1}^{2} \alpha_{il} x_{ijkl} \geq Y_j \quad (j=1,\ldots,n)$$

[4/] The restrictions imposed are those stipulated for Air Quality Control Regions in State Implementation Plans. The restrictions are assumed to apply to all plants regardless of efficiency status.

$$\sum_{j=1}^{n}\sum_{i=1}^{m}\sum_{k=1}^{r}\sum_{l=1}^{2} \gamma_i\beta_i \; x_{ijkl} \le {}_jY_j \quad (j=1,\ldots,n)$$

$$\sum_{i=1}^{m}\sum_{l=1}^{2}\sum_{j=1}^{n}\sum_{k=1}^{r} x_{ijkl} \le X_{il} \quad (i-1,\ldots,m;\ l=1,2)$$

$$x_{ijkl} \ge 0 \quad \text{for all } ijkl$$

$$\sum_{i=1}^{n}\sum_{j=1}^{m}\sum_{k=1}^{r}\sum_{l=1}^{2} x_{ijkl} \le D_{gijk} \quad (k=3,4;\ g=1,\ldots 2)$$

Where: Z^* = total delivered cost of domestic coal based on extraction and transport costs

c_{il} = the cost per unit of extraction in the ith region by the lth mining method

x_{ijkl} = the amount of coal extracted in the ith region by the lth mining method and shipped to the jth region via the kth transportation mode

X_{il} = the total amount of coal extracted in the ith region by the lth mining method

t_{ijk} = the per unit cost of transportation from the ith region shipped to the jth region via the kth mode

Y_j = demand in region j in normal tons = ACTUAL TONS

β_i = percent of sulfur by weight at region i

α_i = factor for converting coal to normal tons in terms of Btu; $\frac{\text{Btu/NORMAL TON}}{\text{Btu/TON}_i}$ for the ith mining method

β_j = percent of sulfur by weight at region j

γ_i = factor for converting coal in terms of Btu and sulfur, a normal ton of coal has 24,000,000 Btu; $\frac{\text{Btu/NORMAL TON}}{\text{Btu/TON}_i}$

D_{kgij} = capacity in tons on mode k (river lock and electric transmission line of g tons) between i and j

The type of coal demanded (sulfur content) at a specific utility plant is determined exogenously to the model since it is based on EPA and State Implementation Plan (SIP) regulations.

Q. Lowell Smith. Did you average sulfur requirements on a plant-by-plant basis or over the AQCR?

A. We computed an average for each county and then weighted each county in each AQCR to determine a coefficient for the AQCR.

The EPA national regulations set minimum standards for point source sulfur emission, prohibiting emission of more than 1.2 pounds of sulfur dioxide (SO_2) per million Btu. [5/] Different levels of actual conformance to this regulation constrains sulfur demand. In the interregional program, different results are obtained and analyzed by setting the sulfur demand constraint, for each demand region, at each of the following levels of conformance:

Level (1)	No sulfur emission standard conformance
Level (2)	1975 sulfur emission standard conformance
Level (3)	1975 conformance + 25% additional conformance
Level (4)	1975 conformance + 30% additional conformance
Level (5)	1975 conformance + 35% additional conformance
Level (6)	1975 conformance + 40% additional conformance
Level (7)	1975 conformance + 45% additional conformance

These conformance levels are explicit percentages of the difference between actual 1975 sulfur conformance and 100% conformance. These conformance levels by demand region are shown in the table in Appendix A. For example, in a demand region such as Philadelphia, Pennsylvania, 1975 conformance with the regulation was 33%--an additional 25% conformance brings the sulfur emission restriction to 50% in level (3), 53% in level (4), 56% in level (5), 60% in level (6), and 63% in level (7). Of course, examination of additional cases leading to a final level of 100% sulfur emission standard conformance is conceivable. Empirically, this objective cannot be achieved by simply redistributing different quality coals; scrubbing capacity would be necessary in some of the demand regions.

[5/] Michael R. LeBlanc., "A Transportation Model for the United States Coal Industry," p. 14.

Q. Lowell Smith. Can scrubbers be installed only on new plants or can they be retrofitted on old plants?

A. The interregional programming model allows a plant to be retrofitted in cases where the plant is allowed a choice. The model will then choose either low sulfur coal to meet the SIP or it will use a scrubber if necessary.

Q. Lowell Smith. Could you go back and change the existing SIPs, i.e., run alternative scenarios using different SIPs, thus requiring the model to put scrubbers on older plants?

A. Yes.

For this analysis air quality regulations, based on the percent of sulfur by weight of a specific coal, are converted to number of pounds per ton of coal demanded and produced.[6/] The demand constraint, incorporating the percent of sulfur by weight, reflects a value of the sulfur content of a specific ton of coal through a coefficient ($_j$). Similarly, the demand constraint for heat content is incorporated in the demand variable (Y_j).[7/] The sulfur constraint can be written as:

$$\sum_{j=1}^{n} \sum_{i=1}^{m} \sum_{k=1}^{r} \sum_{l=1}^{2} \beta_i x_{ijkl} \leq {}_jY_j \quad (j=1,....,m)$$

Where: β_i = amount of sulfur content as a % of weight

β_j = SIP code requirements for % of sulfur by weight at j or other permitted sulfur amount.

x_{ijkl} = the amount of coal extracted in the ith region and shipped to the jth region via the kth transport mode extracted by the lth method.

Y_j = demand for normal tons in region j.

At this point, there are two coal demand constraints, one which says that a minimum quantity of a given heat content coal (in terms of normalized

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[6/] Amount of sulfur by weight is one-half the amount of sulfur dioxide (SO_2).

[7/] Where Y_j = demand in region j in normal tons = Btu/TON$_j$ (ACTUAL TONS/Btu/NORMAL TON)$_j$

tons) in region j must be supplied and the other that sulfur emissions cannot exceed a specified level. The allowable sulfur content by weight varies with the Btu level of the coal since the standard is in terms of SO_2 per million Btu. In order to include both coal quality aspects in the sulfur constraint it is necessary to normalize these characteristics of the regional coals.[8] The following shows the percent by weight of allowable sulfur content for coals of various Btu contents that can be burned within regulatory limits.[9]

Heating Values Btu lb.	Allowable Sulfur Contents (% by Weight)
14,000	0.84
12,000	0.72
10,000	0.60
8,000	0.48
6,000	0.36

The conversion value employed in this study is 0.72% allowable sulfur for 12,000 Btu/lb. because this value is considered a normal pound of coal by the U.S. Bureau of Mines. As stated earlier, a normal ton of coal has 24,000,000 Btu which, if divided by 2,000 pounds, equals 12,000 Btu/lb. For the left hand or supply side of the same two constraints the normalizing process for heat and sulfur content is also included. In the sulfur constraint a factor of γ_i simultaneously represents Btu and sulfur content per ton of coal to be supplied from region i. This constraint now is represented by:

$$\sum_{j=1}^{a} \sum_{i=1}^{n} \sum_{k=1}^{r} \sum_{l=1}^{2} \gamma_i \beta_i \quad x_{ijkl} \leq \beta_j Y_j \quad (j=1,\ldots,n)$$

This constraint assumes that a power plant can mix high and low sulfur coals in amounts necessary to meet the imposed air quality restrictions. Again, once all the production has been converted to a normal percent of sulfur per ton consumers, in minimizing their costs, are indifferent to the source of the coal they receive. Therefore, this combined coal quality constraint is used in the model, instead of individual constraints for heat content and sulfur, since these coal quality characteristics are not independent of each other. The linear program for all types of coal transactions has the following characteristics:

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[8] Michael R. LeBlanc, "A Transportation Model for the United States Coal Industry," p. 15.

[9] U.S. Bureau Mines "Mineral Industry Surveys: Assessment of the Impact of Air Quality Requirements in 1975, 1977, and 1980," p. 19.

(1) Delineation of coal supply regions is based on the attributes of clusters of counties and the interactions of activities among them. Eighty-eight (88) supply regions have been delineated. These regions are capable of delivering coal in 1975 by whatever transportation mode is available from any point in the region. A list of supply centroids is contained in Appendix B, Table 2.

(2) The 1975 demand for coal is based on the consumption by electric utilities. The demand in each county is determined then demand for the region is calculated by adding the quantity demanded in each county contained within the AQCR. A list of demand centroids is contained in Appendix B, Table 1.

(3) Coal is a bulk commodity and, because of this, the cost of transporting coal historically has been a significant portion of the total delivered price to the consumer. In 1932, rail rates accounted for 63% of the delivered price of bituminous coal. In 1973 these costs were still important although they had declined to 30.4% of the destination value. [10/]

There are several modes for transporting coal: rail (mixed freight and unit train), water (river barge, Great Lakes, and tidewater), truck, slurry pipeline, and from mine-mouth electric generating plants. For this analysis, interregional coal movements are restricted to rail, water, and electric power transmission modes of transport.

Rail is the primary method for coal transportation in the United States. Rail movements totaled over 290 million tons in 1973, a 41% increase since 1962. [11/] Because the model developed in this analysis is

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[10/] Interstate Commerce Commission, "Investigation of Railroad Freight Rate Structure," Ex Parte No. 270, p. 92.

[11/] U.S. Department of Interior, Bureau of Mines, IC8706, "Coal Transportation Practices and Equipment Requirements to 1985," p. 2.

normative in nature, it has been designed to optimize coal distribution given statistically estimated 1975 transportation costs to the consumer and actual coal selling prices at the mine.

Q. Jerry Eyster. How were rail rates determined?

A. Through regression equations, including two-stage least squares estimation techniques. The 1975 Waybill Statistics were divided into three groups representing three regions: west of the Mississippi River; the Midwest which represented both intra- and interregional shipments; and the East which was split into Northeast and Southeast. Time in transit was used based on work done by CACI Inc. Some economies of scale factors such as number of shipments, size of shipments, annual tonnage were also used. In addition, there were dummy variables for truck transport, weather conditions, and other factors.

Transportation of coal by water represents approximately 11% (69,094,000 tons) of total coal shipments and is the second most important method of moving coal in the United States. Waterway shipping of coal is conducted on the inland waterways, the Great Lakes, and for export at tidewater ports. Primary rivers used in inland waterway coal movements are the Monongahela, Green, Kanawha, Ohio, Tennessee, Illinois, Mississippi, Allegheny, Arkansas, and Warrior Rivers.

The final mode of coal transportation is the transmission of extra high voltage (EHV) electric power from mine-mouth power plants. Transmission involves the transport of large blocks of power on a point-to-point basis. There are two methods for transporting electric power: alternating current (AC) and direct current (DC) transmissions. Alternating current transmission is best suited for distances of less than 600 miles and for systems in which the trunk line has consumers at intermediate locations. On the other hand, DC transmission is more economic than AC transmission for distances greater than

600 miles and for single origin-destination transmissions. Almost all transmission in the United States is provided by AC overhead lines. As of June 1972, 230 kilvolts (KV), 345 KV, 500 KV, and 765 KV lines accounted for 30.5%, 14,0%, 61.6%, and 0.4% respectively, of the 167,000 miles of transmission line in service. Overhead DC at 400 KV represented about 1% of total transmission lines. Underground EHV transmission has been used solely in urban areas.

Q. Charles Kolstad. Do you use supply cost curves? How do you get a mix of quantities from different sources?

A. The supply curve for each region in this model is perfectly elastic or horizontal up to the amount actually produced in 1975. At that point, there is no further productive capacity and price becomes infinite. In this model the demand is in normalized tons so a power plant is indifferent as to its sources once the qualitative constraints are met. The demand is fulfilled from many sources, if necessary, by minimizing transport costs.

Q. Jerry Eyster. Does that mean there's only one type of coal being shipped?

A. No. The objective function requires actual tons to be shipped even though the constraints are in normalized values.

Q. Jerry Eyster. How does the model know what coals to use to meet the environmental constraints?

A. The sulfur constraint takes the normalized value of the coal demanded in tons and multiplies that by the SIP sulfur restriction performance level to determine the tonnage of sulfur demanded in each region.

Q. George Ferrell. Does the normalization procedure produce results with two or more regions producing quantities greater than zero?

A. Yes, although in some cases only one origin is indicated. It depends on the quantity that the model uses from an individual supply region.

Q. Verne Loose. How do you calculate economic rent if you don't have a supply curve?

A. It is determined by the model dual. The model determines a shadow price, subtracts the cost of burning the sulfur, the producing region supply cost, and anything remaining becomes the economic rent. It's a simple dual formulation.

Q. George Ferrell. You may not calculate the correct dual value if you don't have primal objective function supply curves?

A. The dual value is correct for a comparative statics model of this type. We decided not to develop supply curves which are based solely on mining costs. The models using costs do not accurately determine economic rent because it is impossible to determine the rent shares among market participants. The short run supply curve would be perfectly elastic to a point and would then become perfectly inelastic because there are no more available supplies.

Q. Charles Kolstad. Do you constrain production at base-year levels?

A. Yes, we really asked what would happen if 1975 production levels had to meet stricter conformance requirements. It's a sensitivity test on the sulfur constraints in the model.

Q. Charles Kolstad. What was the reason for constraining production?

A. Because of the short-run nature of the model. We would have increased production levels in any region if more coal could have been made available.

C. Charles Kolstad. With constrained production I can see how you might get infeasibilities and infinite shadow prices.

Q. Jerry Eyster. Does your formulation mean you have less control with coal being shipped across the country for use in power plants which may not be able to accept coal of that specific quality?

A. We had a few shipments from New Mexico to North Carolina.

Q. Larry Parcels. Did high constraints cause low sulfur coal to be shipped all over the country?

A. No, some Western coal went east but there were many small shipments required for blending. The anomalies were dispersed.

C. Lowell Smith. Philadelphia may have such unexpectedly high values because Pennsylvania contains primarily oil-fired plants but has a 0.6 pounds SIP emission limit for SO_2. Since its hard to find 0.6 pound coal in the East the model may produce unusual results in meeting the restrictions. The Pittsburgh area would probably exhibit the same strange results.

III. Results

The incremental cost per ton for burning and emitting sulfur tends to increase as conformance requirements increase at power plants. Also, the spatial pattern of coal distribution and transport mode shares are affected by how much sulfur can be emitted annually in a coal consuming region. Both the marginal cost of sulfur standards and the extent of the change in distribution patterns are directly related to the level of sulfur emission standard conformance. Table 1 of Appendix C (not included in this proceedings but availble from the author) contains the amount of sulfur in thousands of tons burned along with the coal. Also given is the shadow price associated with burning each ton of sulfur for a given level of conformance during 1975 [12/] for each demand region.

In demand regions where restrictive emission standards are imposed there is a non-zero marginal cost for burning an additional ton of sulfur because the sulfur constraint in the linear program is binding. With each higher level of conformance of the State Implementation Plans, the marginal cost increases. Figures 1, 2, 3 and 4 illustrate rising marginal costs for four groups of city sizes. The most dramatic behavior occurs in the group of largest cities. In Northeast cities with a binding sulfur constraint marginal cost rises extremely fast, e.g., costs in Philadelphia rise from $339.90 per ton at the 1975 conformance level to $39,589.60 per ton at the 1975+35% conformance level. Beyond the +35% conformance the linear program model did not have a feasible solution. In the actual 1975 conformance case cities located east of the Mississippi River accounted for 30 out of 36 (83 percent) of the cases where sulfur constraints are binding. At the 1975+35% percent conformance level, where there is a binding sulfur constraint, cities located east of the Mississippi River accounted for 47 out of 58 cases (81 percent). This change is indicative of increased demand for low sulfur, high Btu utility coal from the West and Kentucky and more stringent emission standards throughout the country as shown in Table 1. Supply declines occur as conformance levels increase, in regions that produce low Btu (North Dakota), high sulfur (Illinois), or

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[12/] The shadow price for sulfur represents the marginal cost of burning an additional ton of sulfur at a demand region.

Table 1

State Coal Production, in Million Tons, by Conformance Level

State	1975 0% Conformance	1975 Actual Conformance	1975+25% Conformance	1975+30% Conformance	1975+35% Conformance
Virginia	1.1	1.1	1.4	2.1	2.1
West Virginia	6.4	7.1	7.1	7.1	7.1
Kentucky	100.6	117.1	118.7	119.0	119.8
Pennsylvania	73.9	56.7	54.8	54.7	58.5
Tennessee	8.2	9.4	9.4	9.4	9.4
Alabama	12.5	12.5	12.5	12.5	12.5
Ohio	23.2	21.5	22.0	21.6	22.1
Indiana	6.2	6.2	6.2	5.9	6.2
Illinois	58.8	58.8	58.7	57.3	56.2
Iowa	0.6	0.6	0.6	0.6	0.6
Missouri	10.4	8.1	10.4	9.3	10.4
Kansas	1.3	1.3	1.3	1.3	1.3
Texas	6.5	6.5	6.5	6.8	6.8
Oklahoma	1.9	1.9	1.9	1.9	1.9
North Dakota	3.7	2.5	2.7	2.7	2.7
Colorado	5.0	5.8	5.3	5.3	5.3
New Mexico	7.8	7.8	7.8	7.8	7.8
Wyoming	23.7	23.7	23.7	23.7	23.7
Montana	21.8	22.1	22.1	22.1	22.1
Arizona	7.0	7.0	7.0	7.0	7.0
Washington	3.2	3.2	3.2	3.2	3.2
Utah	1.1	1.1	0.0	0.0	0.0

Figure 1

Marginal Cost of Sulfur Removal for Cities with > 750,000 Population

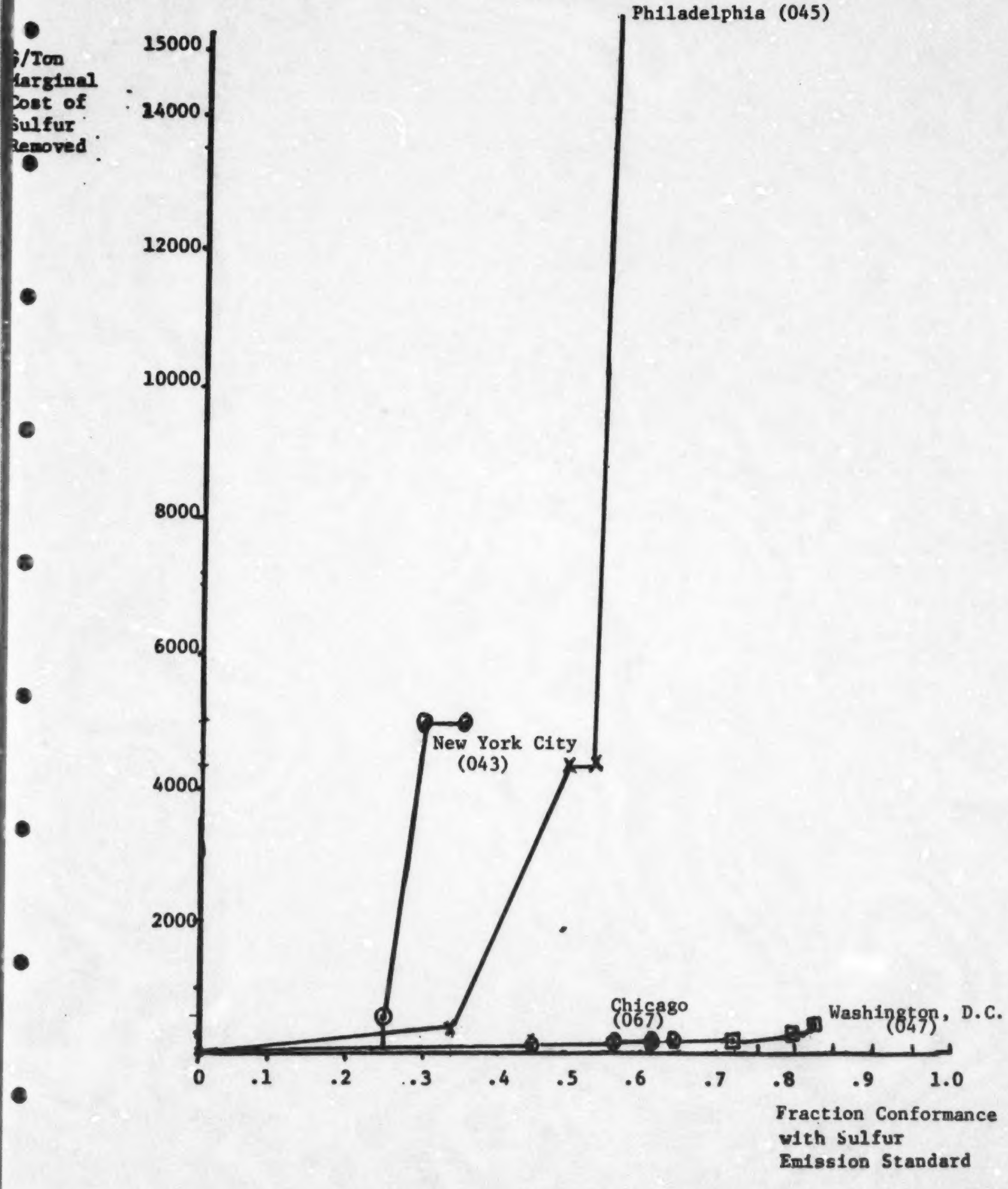
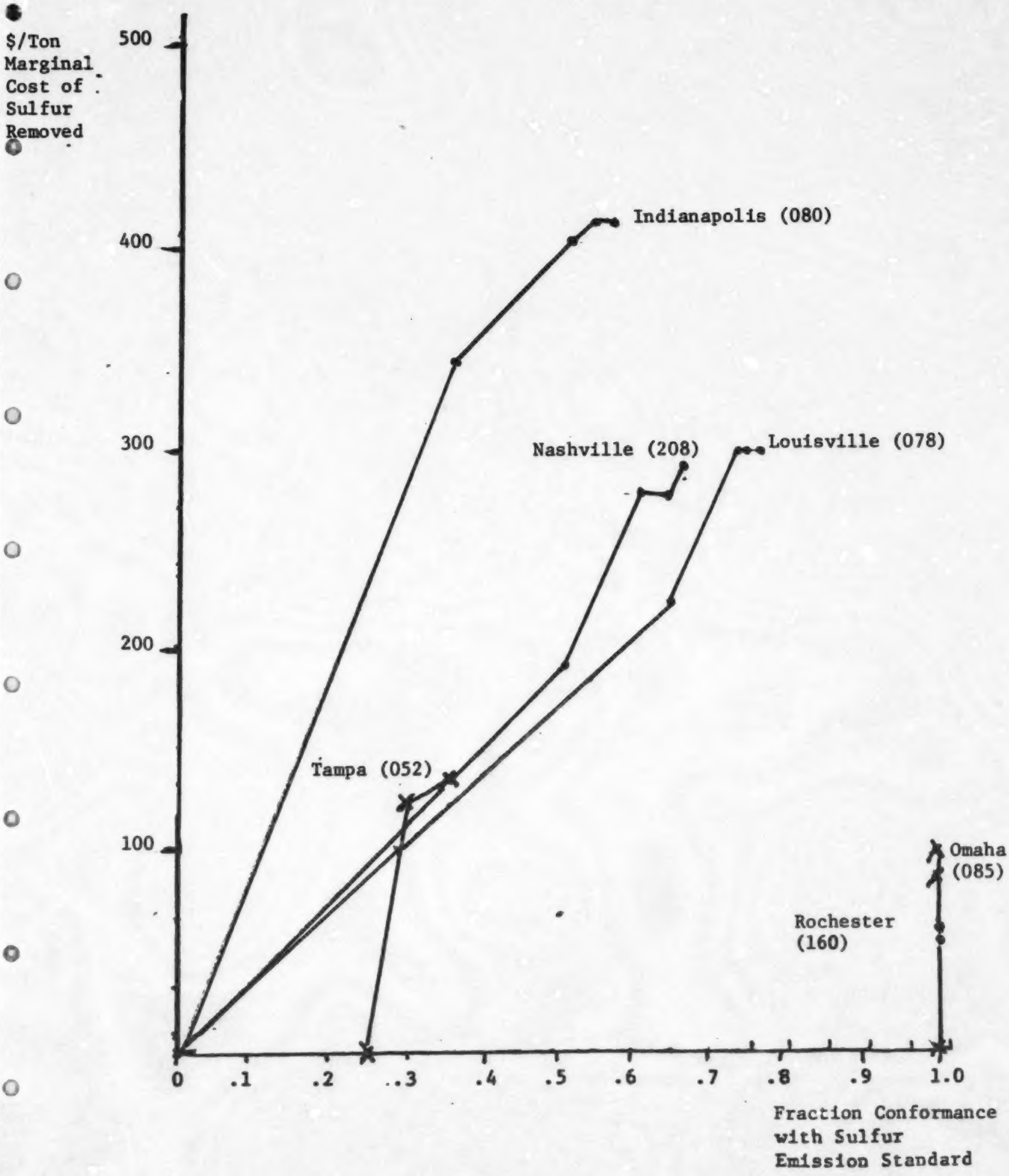


Figure 2

Marginal Cost of Sulfur Removal for Cities with 250,000-750,000 Population



149

Figure 3

Marginal Cost of Sulfur Removal for Cities with 125,000-250,000 Population

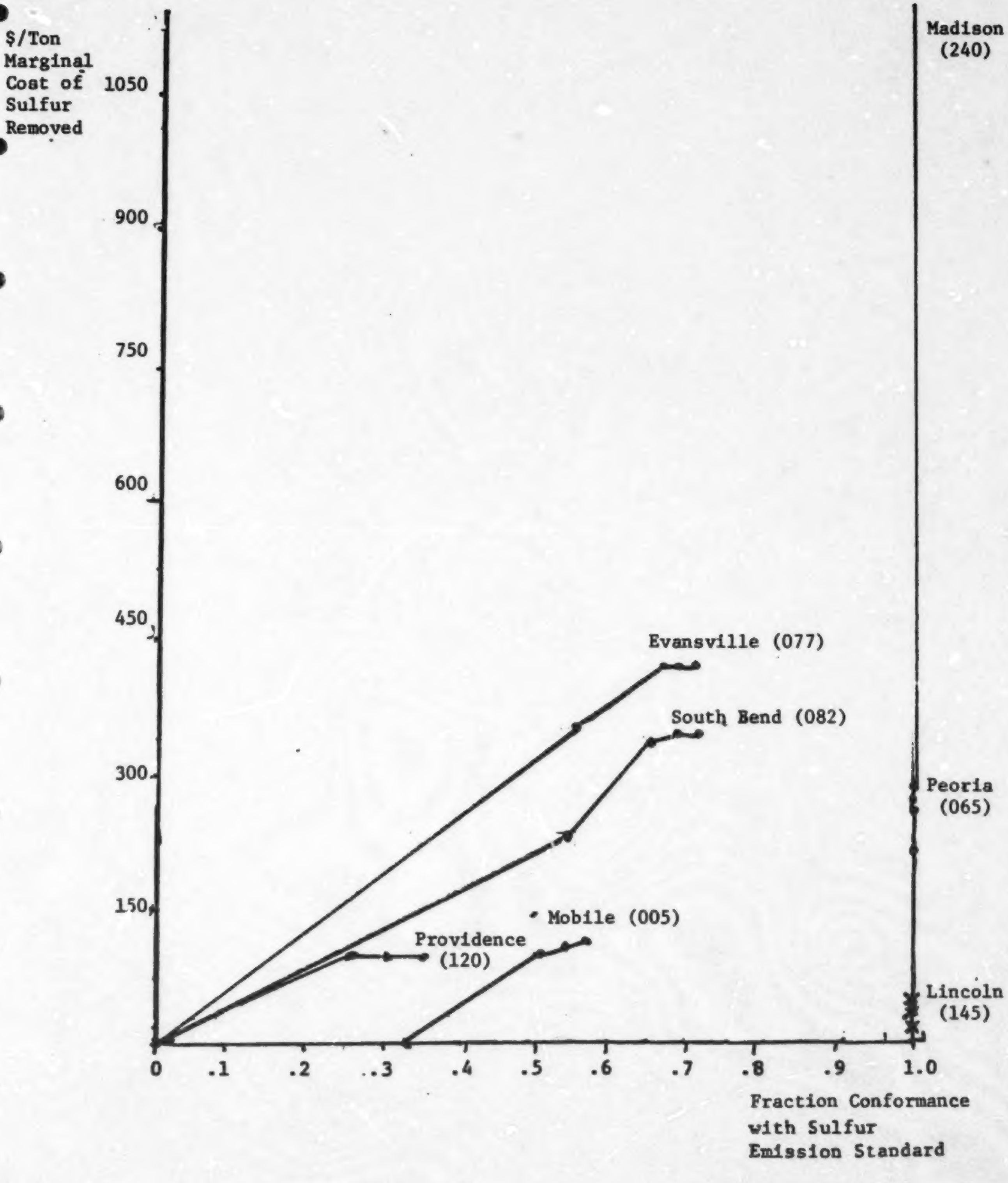
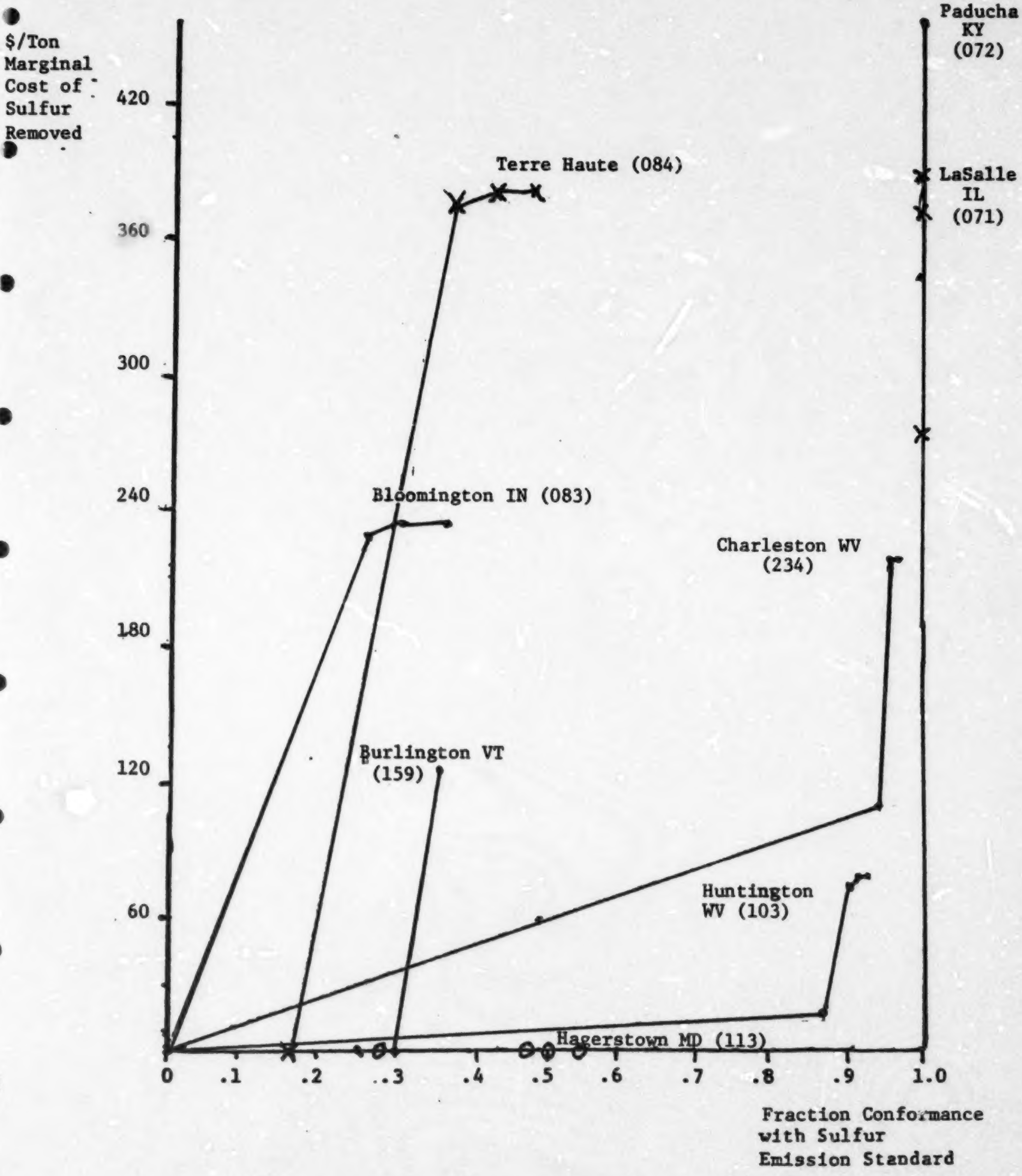


Figure 4

Marginal Cost of Sulfur Removal for Cities with < 125,000 Population



151

low Btu, high sulfur (Pennsylvania) coals. In certain supply regions, shipments from Midwestern bituminous and North Dakota lignite coal regions are significantly reduced. Higher quality coal, not locally produced, is required for consumption therefore raising the total cost of delivered coal to these regions (see Table 1, Appendix C, available from the author). At the same time, as some of the western demand regions give up local coal to send East, regional sulfur emission standards become more restrictive resulting in an increase in the marginal cost of burning sulfur even in regions where low sulfur coal is readily available.

The change in distribution patterns is summarized in Tables 1-5 in Appendix D (available from the author) where aggregated regional shipments are shown respectively. (See Appendix D for distribution patterns for each conformance level.) Also, Appendix E (available from the author) contains a table, for comparison purposes, that includes 1975 actual utility shipments based on Federal Power Commission data. Disaggregated interregional shipment patterns are available upon request. From a comparison of the tables it can be seen that Kentucky coals increasingly supply regions with more restrictive emission standards while western coals tend to substitute for high quality eastern coals. Also, outside of the East, shipment sizes tend to be smaller as conformance levels rise due to a greater requirement for blending.

The requirement for more coal blending also has an effect on transportation mode shares. Table 2 shows how the high volume modes, such as unit train and mine-mouth plant electrical transmission, decrease their shares as regional emission conformance increases. This could be due to an increase in coal blending due to the requirement for higher quality (lower sulfur) coal for the same level of demand. Another reason for this

Table 2

Mode	0% Conformance	1975 Conformance	1975+25% Conformance	1975+30% Conformance	1975+35% Conformance
Regulated Rail	42.5%	50.6%	53.2%	53.2%	53.1%
Unit Train	18.6	17.0	15.4	15.2	14.9
Barge	17.6	11.6	11.3	11.7	12.5
Mine Mouth Power Transmission	21.4	20.8	20.1	19.9	19.5
Total	100.0	100.0	100.0	100.0	100.0
Total Tons (000,000)	388.9	387.4	387.2	387.0	386.8

reduction in shares may be due to the non-existence of unit train tariffs and high voltage transmission lines between the new origins and destinations. [13/] Some destinations would no longer be supplied by high volume modes from one supply region because demand regions now may require a large number of small, high quality coal shipments from many origins.

[13/] The non-existence of origin-destination tariffs is due to either tariffs not registered at the I.C.C. or inadvertent exclusion from the linear program model.

IV. Conclusions

This analysis has shown that if utilities were required to conform in full to regional sulfur emission standards by redistributing coal nationwide, they could not.[14] Close scrutiny showed that utilities could only acquire the right types of coal to attain actual 1975 plus 35 percent regional conformance with the sulfur emission standards which, in some Air Quality Control Regions, is far from 100 percent conformance. Greater conformance with emission standards has an impact on regional shipment patterns and allocation of coal movements among transportation modes. It is clear that supply regions with high sulfur, low Btu coals, or a combination of both, would have a reduction in the amount of coal extracted as sulfur restrictions are tightened. Furthermore, in some regions in Pennsylvania, Indiana, Ohio, Illinois, and North Dakota, there are reductions in coal supplied and exported. Thus, changes in the conformance with sulfur standards do have a substantial impact on regional coal utility markets.

Restrictive sulfur emission standards requiring more conformance than occurred in 1975 imply either that more low sulfur/high Btu coals be made available (in some cases restrictions may be too constraining for any coal produced) or that stack gas scrubbers be employed extensively in power plants. Because of the effect of sulfur emission standards further research is necessary to assess how strict emissions can affect the utilization of unit trains in the West and to examine the impact of these sulfur standards on the coal industry in the Midwest and the Northeast. Conformance with emission standards can greatly affect the vitality of this industry in these regions as has been shown in this paper. If scrubbers are used, local coal can be burned at the power plants but at a much higher cost per million Btu. On the other hand, low sulfur coal, if used, must be imported at a high price. Since coal demand should rise in the Midwest and Northeast during the next 20 years, utilities must make decisions about what type of coal can be consumed and where they can get it. The States of Ohio, Indiana, and Illinois may very well be the areas where the low sulfur western coal vs. stack gas scrubber tradeoff can be tested and evaluated.

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[14] The analysis assumes all plants are required to abide by the imposed standards.

Q. Hoff Stauffer. You mentioned earlier that this was a short run model and there were questions concerning the correctness of the economic rent calculations. Would it therefore make sense to use this model for analysis of Federal leasing strategies?

A. Yes, because we can compare the sensitivity of leasing strategies in a comparative statics sense. In the leasing program analysis, once the least-cost locations are found, we will run sets of different cash flows representing alternative mine sizes in each region to see if production occurs for given minimum selling prices or use escalated f.o.b. prices from a base year.

Q. Jerry Eyster. Shouldn't there be a supply function to represent new production? Would rents occur if there is new production and, if they are anticipated by the mining industry, wouldn't the production level respond?

A. It would. Our problem is in estimating reasonable supply curves. In a strict economic sense we do not get supply curves out of cash flows and representative mines unless there is no economic rent. Your guess is as good as mine as to whether the market forces or the Federal Government will be able to reduce economic rent to a normal rate of return in order to use cash flow derived supply curves. I might add that any cash flow procedure assumes a specific mine size which may not accurately depict the actual market transaction for a specific coal under examination.

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Appendix A

Table 1

Utility Coal Flows by Origins and Destinations for 0% Conformance

Destination[1/] (region numbers)	Origin State[2/]	Quantity (000 Tons)
Rhode Island, New Hampshire, Vermont (120), (121), (159)	West Virginia	986.8
	Pennsylvania	452.0
Total		1438.8
Southeast New York Eastern Pennsylvania, Delaware, Washington, D.C., Eastern Maryland, New Jersey (43), (45), (46), (47), (115), (116), (150), (151), (163), (196)	Pennsylvania	12431.0
	New Mexico	1650.9
	Colorado	197.5
Total		14279.4
Eastern Kentucky, West Virginia, Western Maryland, West New York, Western Pennsylvania, Virginia, Eastern Ohio (101), (102), (103), (113), (160), (162), (164), (178), (181), (195), (197), (226), (231), (223), (234), (235)	Kentucky	5243.1
	Ohio	14055.8
	Pennsylvania	55047.5
	West Virginia	5380.5
Total		79726.9
Southeast Virginia, North Carolina, South Carolina (136), (165), (166), (167), (169), (170), (171), (199), (200), (201), (202), (204), (222), (224), (225)	Colorado	2348.1
	Virginia	1060.0
	Kentucky	10203.1
	Kansas	1284.0
	Tennessee	4031.0
	Oklahoma	882.6
	Missouri	3268.0
Total		23076.8
Southwest South Carolina, Florida, Georgia (49), (50), (52), (53), (54), (56), (58), (59)	Tennessee	3711.4
	Kentucky	5507.6
	Alabama	1660.1
Total		10879.1
Northern Alabama, Northwest Georgia, South Central Kentucky, Tennessee (7), (55), (105), (207), (208), (209)	Illinois	776.6
	Kentucky	34459.5
	Tennessee	255.1
Total		35491.2

Table 1 (continued)

Destination[1] (region numbers)	Origin State[2]	Quantity (000 Tons)
Southern Alabama (3), (4), (5)	Alabama	10883.9
	Illinois	3067.2
	Tennessee	166.5
Total		14117.6
Ohio, Michigan, North Central Kentucky (79), (122), (123), (124), (125), (173), (174), (175), (176), (180), (183)	Kentucky	15667.3
	Ohio	9123.5
	Pennsylvania	5928.3
	Illinois	6989.1
	West Virginia	770.7
Total		38478.9
Western Kentucky, Indiana (72), (76), (77), (78), (80), (81), (82), (83), (84)	Kentucky	22342.5
	Illinois	12802.7
	Indiana	5850.9
Total		40996.0
Southwest Tennessee, Northwest Louisiana, Western Mississippi, Southern Missouri, East Texas (18), (22), (134), (138), (139) (212)	Kentucky	1227.9
	Texas	6481.0
	Oklahoma	1062.4
	Montana	2517.2
Total		11288.5
Northern Michigan, Minnesota, Wisconsin (126), (127), (128), (129), (131), (132), (133), (237), (238), (239), (240)	Kentucky	1612.8
	Illinois	8125.3
	Montana	9306.0
	North Dakota	539.1
Total		19583.2
Illinois, Eastern Iowa, Eastern Missouri (65), (66), (67), (68), (69), (70), (71), (73), (74), (75)	Indiana	305.2
	Kentucky	4342.4
	Illinois	22935.8
	Missouri	7172.0
	Wyoming	8583.9
	Iowa	612.0
Total		43951.3
Northern Missouri, Eastern Kansas (94), (96), (99), (137)	Wyoming	3254.3
	Illinois	2705.6
	Colorado	118.3
	Montana	1072.9
Total		7151.1

Table 1 (continued)

Destination[1/] (region numbers)	Origin State[2/]	Quantity (000 Tons)
Iowa, Nebraska, Southeast South Dakota (85), (86), (87), (88), (89), (90), (92), (145), (146)	Colorado	29.7
	Wyoming	360.1
	Montana	5671.9
Total		6061.7
North Dakota, South Dakota (172), (205), (206)	Wyoming	277.0
	Montana	2162.4
	North Dakota	3141.0
Total		5880.4
Colorado (35), (36), (38), (40)	Wyoming	4276.3
	Colorado	2173.4
Total		6449.7
Eastern Montana, Oregon, Wyoming (140), (143), (193), (241), (243)	Wyoming	5704.5
	Montana	1023.5
	Washington	3249.7
Total		9977.7
Southeast Nevada, Utah, Arizona (13), (14), (219), (220)	Utah	1054.1
	Arizona	6986.0
	Colorado	101.1
	New Mexico	6118.1
	Wyoming	1219.9
	Illinois	1374.8
Total		16854.0

1/ Destination regions are combined to macro-regions.

2/ Origin regions are combined by centroid location to State levels.

Appendix A

Table 2

Utility Coal Flows by Origins and Destinations for Actual 1975 Conformance

Destination[1/] (region numbers)	Origin State[2/]	Quantity (000 Tons)
Rhode Island, New Hampshire	Kentucky	486.3
Vermont	West Virginia	986.7
(120), (121), (159)		
Total		1473.5
Southeast New York,	Kentucky	3012.6
Eastern Pennsylvania, Delaware,	Pennsylvania	8181.1
Washington, D.C., Eastern	New Mexico	1650.9
Maryland, New Jersey	Virginia	971.7
(43), (45), (6), (47), (115),	Ohio	478.0
(116), (150), (151), (163), (196)		
Total		14294.3
Eastern Kentucky, West Virginia,	Kentucky	14342.5
Western Maryland, West New York,	Ohio	10725.6
Western Pennsylvania, Virginia,	Pennsylvania	47351.0
Eastern Ohio	West Virginia	5380.5
(101), (102), (103), (113), (160),	Tennessee	1079.0
(162), (164), (178), (181), (195),		
(197), (226), (231), (223), (234),		
(235)		
Total		78878.6
Southeast Virginia, North Carolina,	Texas	482.5
South Carolina	Virginia	51.7
(136), (165), (166), (167), (169),	Kentucky	14131.9
(170), (171), (199), (200), (201),	Kansas	1284.0
(202), (204), (222), (224), (225)	Colorado	3088.2
	Tennessee	2952.0
	Oklahoma	882.6
Total		22872.9
Southwest South Carolina, Florida,	Tennessee	2949.7
Georgia	Kentucky	4479.1
(49), (50), (52), (53), (54), (56),	Alabama	3562.3
(58), (59)		
Total		10991.1
Northern Alabama, Northwest Georgia,	Illinois	318.2
South Central Kentucky, Tennessee	Kentucky	35389.3
(7), (55), (105), (207), (208),		
(209)		
Total		35707.5

Table 2 (continued)

Destination 1/ (region numbers)	Origin State 2/	Quantity (000 Tons)
Southern Alabama (3), (4), (5)	Alabama	8981.7
	Illinois	5494.1
Total		14475.8
Ohio, Michigan, North Central Kentucky (79), (122), (123), (124), (125), (173), (174), (175), (176), (180), (183)	Kentucky	15510.3
	Ohio	10297.4
	Pennsylvania	1204.6
	Illinois	11620.4
	West Virginia	770.7
Total		39430.4
Western Kentucky, Indiana (72), (76), (77), (78), (80), (81), (82), (83), (84)	Illinois	13054.0
	Indiana	4299.5
	Kentucky	19651.6
	Tennessee	2425.3
Total		39430.4
Southwest Tennessee, Northwest Louisiana, Western Mississippi, Southern Missouri, East Texas (18), (22), (134), (138), (139) (212)	Kentucky	1620.3
	Texas	5998.5
	Oklahoma	1062.4
	Montana	2517.2
	Illinois	31.6
Total		11230.0
Northern Michigan, Minnesota, Wisconsin (126), (127), (128), (129), (131), (132), (133), (237), (238), (239), (240)	Colorado	210.3
	Illinois	7381.8
	Kentucky	1964.1
	Montana	9791.4
	North Dakota	302.7
	Virginia	36.6
	Wyoming	42.8
Total		19729.7
Illinois, Eastern Iowa, Eastern Missouri (65), (66), (67), (68), (69), (70), (71), (73), (74), (75)	Indiana	1856.5
	Illinois	16015.4
	Kentucky	5796.4
	Missouri	7172.0
	Montana	6030.6
	Wyoming	8149.4
Total		45020.3
Northern Missouri, Eastern Kansas (94), (96), (99), (137)	Illinois	3223.1
	Wyoming	719.4
	Colorado	420.0
	Missouri	2560.1
Total		6922.6

Table 2 (continued)

Destination[1] (region numbers)	Origin State[2]	Quantity (000 Tons)
Iowa, Nebraska, Southeast South Dakota (85), (86), (87), (88), (89), (90), (92), (145), (146)	Kentucky	732.2
	Missouri	707.9
	Iowa	622.0
	Wyoming	3134.8
	Illinois	124.6
Total		5321.6
North Dakota, South Dakota (172), (205), (206)	Montana	3040.0
	North Dakota	2150.2
Total		5190.2
Colorado (35), (36), (38), (40)	Colorado	1632.2
	Wyoming	4912.6
Total		6544.8
Eastern Montana, Oregon, Wyoming (140), (143), (193), (241), (243)	Colorado	276.2
	Wyoming	5704.5
	Montana	685.8
	Washington	3249.7
Total		9916.2
South Nevada, Utah, Arizona (13), (14), (219), (220)	Utah	1054.1
	Arizona	6986.0
	New Mexico	6118.1
	Colorado	161.5
	Wyoming	1012.5
	Illinois	1513.7
Total		16845.9

[1] Destination regions are combined to macro-regions.

[2] Origin regions are combined by centroid location to State levels.

Appendix A

Table 3

Utility Coal Flows by Origins and Destinations for 1975+25% Conformance

Destination[1] (region numbers)	Origin State[2]	Quantity (000 Tons)
Rhode Island, New Hampshire Vermont (120), (121), (159)	Kentucky	1403.6
	Pennsylvania	114.6
Total		1517.9
Southeast New York, Eastern Pennsylvania, Delaware, Washington, D.C., Eastern Maryland, New Jersey (43), (45), (46), (47), (115), (116), (150), (151), (163), (196)	Kentucky	3744.6
	Pennsylvania	6590.1
	Ohio	478.0
	New Mexico	2094.1
	Virginia	1400.7
Total		14307.5
Eastern Kentucky, West Virginia, Western Maryland, West New York, Western Pennsylvania, Virginia, Eastern Ohio (101), (102), (103), (113), (160), (162), (164), (178), (181), (195), (235)	Kentucky	13618.6
	Ohio	10012.6
	Pennsylvania	46620.1
	West Virginia	7138.0
	Tennessee	1262.5
	Missouri	215.6
Total		78867.4
Southeast Virginia, North Carolina, South Carolina (136), (165), (166), (167), (169), (170), (171), (199), (200), (201), (202), (204), (222), (224), (225)	Oklahoma	1945.0
	Pennsylvania	159.3
	Kentucky	14623.5
	Kansas	793.2
	Colorado	3343.3
	Tennessee	1625.8
	Texas	482.5
Total		22972.6
Southwest South Carolina, Florida, Georgia (49), (50), (52), (53), (54), (56), (58), (59)	Tennessee	2949.7
	Kentucky	8172.6
Total		11122.3
Northern Alabama, Northwest Georgia, South Central Kentucky, Tennessee (7), (55), (105), (207), (208), (209)	Alabama	1706.3
	Illinois	318.2
	Kentucky	32474.3
	Tennessee	1142.7
Total		35641.5

Table 3 (continued)

Destination[1] (region numbers)	Origin State[2]	Quantity (000 Tons)
Southern Alabama (3), (4), (5)	Alabama	10837.7
	Kentucky	122.0
	Illinois	3183.7
Total		14143.4
Ohio, Michigan, North Central Kentucky (79), (122), (123), (124), (125), (173), (174), (175), (176), (180), (183)	Kentucky	13863.3
	Ohio	11557.4
	Pennsylvania	1350.7
	Illinois	11620.4
Total		39391.8
Western Kentucky, Indiana (72), (76), (77), (78), (80), (81), (82), (83), (84)	Tennessee	2425.3
	Illinois	7644.5
	Indiana	6156.0
	Kentucky	22625.9
Total		38851.6
Southwest Tennessee, Northwest Louisiana, Western Mississippi, Southern Missouri, East Texas (18), (22), (134), (138), (139) (212)	Montana	489.0
	Kentucky	1620.3
	Texas	5998.5
	Kansas	490.8
	Missouri	2290.0
	Illinois	31.6
Total		10920.2
Northern Michigan, Minnesota, Wisconsin (126), (127), (128), (129), (131), (132), (133), (237), (238), (239), (240)	Illinois	7763.7
	Kentucky	1612.8
	Montana	9871.9
	North Dakota	366.4
	Colorado	175.7
Total		19790.5
Illinois, Eastern Iowa, Eastern Missouri (65), (66), (67), (68), (69), (70), (71), (73), (74), (75)	Illinois	18568.2
	Kentucky	3450.4
	Missouri	6006.3
	Montana	6145.6
	Wyoming	11500.0
Total		45670.5
Northern Missouri, Eastern Kansas (94), (96), (99), (137)	Illinois	5477.4
	Missouri	950.1
Total		6427.5

Table 3 (continued)

Destination[1] (region numbers)	Origin State[2]	Quantity (000 Tons)
Iowa, Nebraska, Southeast South Dakota (85), (86), (87), (88), (89), (90), (92), (145), (146)	Illinois	974.4
	Kentucky	391.3
	Missouri	978.0
	Iowa	622.0
	Wyoming	380.6
	Montana	1969.7
Total		5316.0
North Dakota, South Dakota (172), (205), (206)	Montana	2903.1
	North Dakota	2298.2
Total		5201.3
Colorado (35), (36), (38), (40)	Wyoming	5117.8
	Colorado	1454.2
Total		6572.0
Eastern Montana, Oregon, Wyoming (140), (143), (193), (241), (243)	Colorado	276.2
	Wyoming	5704.5
	Montana	685.8
	Washington	3249.7
Total		9916.2
Southeast Nevada, Utah, Arizona (13), (14), (219), (220)	Illinois	3153.0
	Arizona	6986.0
	New Mexico	5674.9
	Colorado	56.6
	Wyoming	973.1
Total		16843.6

[1] Destination regions are combined to macro-regions.

[2] Origin regions are combined by centroid location to State levels.

Appendix A

Table 4

Utility Coal Flows by Origins and Destinations for 1975+30% Conformance

Destination[1/] (region numbers)	Origin State[2/]	Quantity (000 Tons)
Rhode Island, New Hampshire Vermont (120), (121), (159)	Kentucky	1295.9
	Pennsylvania	214.3
Total		1510.8
Southeast New York, Eastern Pennsylvania, Delaware, Washington, D.C., Eastern Maryland, New Jersey (43), (45), (46), (47), (115), (116), (150), (151), (163), (196)	Kentucky	3124.5
	Pennsylvania	6521.8
	Ohio	478.0
	New Mexico	2094.1
	Virginia	2059.8
Total		14278.2
Eastern Kentucky, West Virginia, Western Maryland, West New York, Western Pennsylvania, Virginia, Eastern Ohio (101), (102), (103), (113), (160), (162), (164), (178), (181), (195), (197), (226), (231), (233), (234), (235)	Kentucky	13660.1
	Ohio	10930.0
	Pennsylvania	46544.4
	West Virginia	7138.0
	Missouri	215.6
	Tennessee	449.2
Total		78937.3
Southeast Virginia, North Carolina, South Carolina (136), (165), (166), (167), (169), (170), (171), (199), (200), (201), (202), (204), (222), (224), (225)	Texas	795.9
	Kentucky	14521.2
	Kansas	674.4
	Tennessee	1625.8
	Colorado	3306.8
	Oklahoma	1945.0
Total		22869.1
Southwest South Carolina, Florida, Georgia (49), (50), (52), (53), (54), (56), (58), (59)	Tennessee	2949.7
	Kentucky	8162.8
Total		11112.5
Northern Alabama, Northwest Georgia, South Central Kentucky, Tennessee (7), (55), (105), (207), (208), (209)	Alabama	1435.3
	Illinois	318.2
	Kentucky	31919.8
	Tennessee	1956.0
Total		35629.3

Table 4 (continued)

Destination[1] (region numbers)	Origin State[2]	Quantity (000 Tons)
Southern Alabama	Alabama	11108.7
(3), (4), (5)	Kentucky	122.0
	Illinois	2865.7
Total		14096.4
Ohio, Michigan, North Central	Kentucky	15712.1
Kentucky	Ohio	10640.0
(79), (122), (123), (124),	Pennsylvania	1395.0
(125), (173), (174), (175),	Illinois	11620.4
(176), (180), (183)		
Total		39367.5
Western Kentucky, Indiana	Tennessee	2425.3
(72), (76), (77), (78), (80),	Illinois	6334.5
(81), (82), (83), (84)	Indiana	5924.7
	Kentucky	23721.5
Total		38405.9
Southwest Tennessee, Northwest	Illinois	31.6
Louisiana, Western Mississippi,	Kentucky	1620.3
Southern Missouri, East Texas	Texas	5998.5
(18), (22), (134), (138), (139)	Kansas	609.6
(212)	Missouri	2162.0
	Montana	489.0
Total		10911.0
Northern Michigan, Minnesota,	Illinois	7763.7
Wisconsin	Kentucky	1612.8
(126), (127), (128), (129), (131),	Montana	9871.9
(132), (133), (237), (238), (239),	North Dakota	356.4
(240)	Colorado	175.7
Total		19780.5
Illinois, Eastern Iowa, Eastern	Illinois	18568.2
Missouri	Kentucky	3128.1
(65), (66), (67), (68), (69), (70),	Missouri	6006.3
(71), (73), (74), (75)	Montana	6145.6
	Wyoming	11880.6
Total		45728.8
Northern Missouri, Eastern	Illinois	5477.4
Kansas	Missouri	950.1
(94), (96), (99), (137)		
Total		6427.5

Table 4 (continued)

Destination[1/] (region numbers)	Origin State[2/]	Quantity (000 Tons)
Iowa, Nebraska, Southeast South Dakota (85), (86), (87), (88), (89), (90), (92), (145), (146)	Illinois	1141.8
	Kentucky	382.1
	Missouri	1106.0
	Iowa	622.0
	Wyoming	37.8
	Montana	1969.7
Total		5259.4
North Dakota, South Dakota (172), (205), (206)	Montana	2903.1
	North Dakota	2298.2
Total		5201.3
Colorado (35), (36), (38), (40)	Wyoming	5080.2
	Colorado	1490.7
Total		6570.0
Eastern Montana, Oregon, Wyoming (140), (143), (193), (241), (243)	Colorado	276.2
	Wyoming	5704.5
	Montana	685.8
	Washington	3249.7
Total		9916.2
Southeast Nevada, Utah, Arizona (13), (14), (219), (220)	Illinois	3153.0
	Arizona	6986.0
	New Mexico	5694.9
	Colorado	56.6
	Wyoming	973.1
Total		16843.6

1/ Destination regions are combined to macro-regions.

2/ Origin regions are combined by centroid location to State levels.

Appendix A

Table 5

Utility Coal Flows by Origins and Destinations for 1975+35% Conformance

Destination[1/] (region numbers)	Origin State[2/]	Quantity (000 Tons)
Rhode Island, New Hampshire, Vermont (120), (121), (159)	Kentucky	1217.8
	West Virginia	286.8
Total		1504.6
Southeast New York, Eastern Pennsylvania, Delaware, Washington, D.C., Eastern Maryland, New Jersey (43), (45), (46), (47), (115), (116), (150), (151), (163), (196)	Kentucky	2278.0
	Pennsylvania	6633.6
	Virginia	2068.6
	Ohio	478.0
	New Mexico	2094.1
	Colorado	857.1
Total		14409.3
Eastern Kentucky, West Virginia, Western Maryland, West New York, Western Pennsylvania, Virginia, Eastern Ohio (101), (102), (103), (113), (160), (162), (164), (178), (181), (195), (197), (226), (231), (233), (234), (235)	Kentucky	13807.3
	Ohio	12337.9
	Pennsylvania	49199.9
	West Virginia	7138.0
	Missouri	215.6
Total		82698.7
Southeast Virginia, North Carolina, South Carolina (136), (165), (166), (167), (169), (170), (171), (199), (200), (201), (202), (204), (222), (224), (225)	Tennessee	1625.8
	Pennsylvania	159.3
	Kentucky	14951.6
	Oklahoma	1945.0
	Texas	803.4
	Kansas	639.1
	Colorado	2834.4
Total		22958.6
Southwest South Carolina, Florida, Georgia (49), (50), (52), (53), (54), (56), (58), (59)	Tennessee	2949.7
	Kentucky	8156.2
Total		11105.9
Northern Alabama, Northwest Georgia, South Central Kentucky, Tennessee (7), (55), (105), (207), (208), (209)	Illinois	318.2
	Kentucky	31701.7
	Alabama	1196.6
	Tennessee	2405.2
Total		35621.8

Table 5 (continued)

Destination[1/] (region numbers)	Origin State[2/]	Quantity (000 Tons)
Southern Alabama (3), (4), (5)	Alabama	11347.3
	Kentucky	122.0
	Illinois	2585.7
Total		14055.0
Ohio, Michigan, North Central Kentucky (79), (122), (123), (124), (125), (173), (174), (175), (176), (180), (183)	Kentucky	16227.4
	Ohio	9328.5
	Pennsylvania	2193.4
	Ilinois	11620.4
Total		39369.6
Western Kentucky, Indiana (72), (76), (77), (78), (80), (81), (82), (83), (84)	Tennessee	2425.3
	Illinois	5370.8
	Indiana	6156.0
	Kentucky	24562.6
Total		38514.7
Southwest Tennessee, Northwest Louisiana, Western Mississippi, Southern Missouri, East Texas (18), (22), (134), (138), (139), (212)	Illinois	31.6
	Kentucky	1620.3
	Texas	5998.5
	Kansas	644.9
	Missouri	2124.0
	Montana	489.0
Total		10908.2
Northern Michigan, Minnesota, Wisconsin (126), (127), (128), (129), (131), (132), (133), (237), (238), (239), (240)	Kentucky	1612.8
	Colorado	170.7
	Illinois	7763.7
	Montana	9855.0
	North Dakota	356.4
Total		19758.6
Illinois, Eastern Iowa, Eastern Missouri (65), (66, (67), (68), (69), (70), (71), (73), (74), (75)	Illinois	18568.2
	Kentucky	3091.4
	Missouri	6006.2
	Montana	6145.6
	Wyoming	11880.6
Total		45692.0
Northern Missouri, Eastern Kansas (94), (96), (99), (137)	Illinois	5477.4
	Missouri	950.1
Total		6427.5

Table 5 (continued)

Destination[1] (region numbers)	Origin State[2]	Quantity (000 Tons)
Iowa, Nebraska, Southeast South Dakota (85), (86), (87), (88), (89), (90), (92), (145), (146)	Kentucky	454.7
	Missouri	1144.0
	Iowa	622.0
	Wyoming	37.7
	Montana	1986.6
Total		5255.4
North Dakota, South Dakota (172), (205), (206)	Montana	2903.1
	North Dakota	2298.2
Total		5201.2
Colorado (35), (36), (38), (40)	Colorado	1111.0
	Wyoming	5080.2
	Illinois	375.7
Total		6566.9
Eastern Montana, Oregon, Wyoming (140), (143), (193), (241), (243)	Colorado	276.2
	Wyoming	5704.5
	Montana	685.8
	Washington	3249.7
Total		9916.2
Southeast Nevada, Utah, Arizona (13), (14), (219), (220)	Illinois	3153.0
	Arizona	6986.0
	New Mexico	5674.9
	Colorado	56.6
	Wyoming	973.1
Total		16843.6

[1] Destination regions are combined to macro-regions.

[2] Origin regions are combined by centroid locations to State levels.

Appendix B

Table 1

1975 Actual Utility Coal Shipments

Supply Region	Demand Region	Quantity (000 Tons)
Birmingham, AL (3)	Gadsden, AL (3)	183.0
	Birmingham, AL (4)	9593.3
	Mobile, AL (5)	2089.5
	Chattanooga, TN (55)	1804.0
	Atlanta, GA (56)	1002.8
Total		14772.6
Jasper, TN (4)	Birmingham, AL (4)	50.2
	Decatur, AL (7)	168.4
	Springfield, IL (75)	10.8
	Knoxville, TN (207)	112.7
Total		342.1
Oak Ridge, TN (7)	Macon, GA (54)	1626.6
	Atlanta, GA (56)	130.7
	Asheville, NC (171)	297.3
	Dayton, OH (173)	40.5
	Knoxville, TN (207)	5445.0
	Richmond, VA (225)	38.8
Total		7578.9
Lebanon, VA (8)	Washington, DC (47)	33.3
	Cincinnati, OH (79)	17.7
	Huntington, WV (103)	81.0
	Raleigh, NC (166)	106.1
	Knoxville, TN (207)	1430.4
Total		1668.5
Pikeville, KY (9)	Philadelphia, PA (45)	321.8
	Washington, DC (47)	454.8
	Macon, GA (54)	1496.1
	Chattanooga, TN (55)	1166.2
	Atlanta, GA (56)	473.1
	Savannah, GA (58)	258.5
	Paducah, KY (72)	117.9
	Muncie, IN (76)	79.1
	Cincinnati, OH (79)	405.5
	Ft. Wayne, IN (81)	1427.9
	Lexington, KY (102)	710.9
	Huntington, WV (103)	1770.5
	Toledo, OH (124)	1380.6

Supply Region	Demand Region	Quantity (000 Tons)
Pikeville, KY (9) (continued)	Kalamazzo, MI (125)	12.0
	Marquette, MI (126)	629.3
	Greensboro, NC (136)	148.4
	Scranton, PA (151)	472.9
	Rochester, NY (160)	45.8
	Hickory, NC (165)	3516.7
	Raleigh, NC (166)	1732.6
	Charlotte, NC (167)	2275.6
	Wilmington, NC (170)	813.6
	Asheville, NC (171)	106.5
	Dayton, OH (173)	902.0
	Cleveland, OH (174)	238.4
	Dubois, PA (178)	1.3
	Wheeling, WV (181)	117.8
	Pittsburgh, PA (197)	735.6
	Charleston, SC (199)	362.4
	Columbia, SC (200)	307.4
	Florence, SC (201)	286.1
	Spartanburg, SC (202)	371.3
	Georgetown, SC (204)	65.7
	Knoxville, TN (207)	3001.5
	Lynchburg, VA (222)	22.4
	Fredericksburg, VA (224)	233.9
	Richmond, VA (225)	201.8
	Roanoke, VA (226)	478.7
	Martinsburg, WV (233)	722.3
	Charleston, WV (234)	199.4
	Green Bay, WI (237)	881.4
	Wausan, WI (238)	32.0
Total		28977.7
Middlesboro, KY (10)	Jacksonville, FL (49)	92.5
	Augusta, GA (53)	446.2
	Macon, GA (54)	142.3
	Chattanooga, TN (55)	734.2
	Atlanta, GA (56)	1744.7
	Albany, GA (59)	410.0
	Springfield, IL (75)	40.0
	Muncie, IN (76)	1.9
	Ft. Wayne, IN (81)	45.9
	Lexington, KY (102)	777.7
	Bowling Green, KY (105)	42.5
	Baltimore, MD (115)	4.2
	Buffalo, NY (162)	270.9
	Hickory, NC (165)	12.1
	Raleigh, NC (166)	209.2
	Charlotte, NC (167)	2.4
	Asheville, NC (171)	486.8
	Dayton, OH (173)	22.4
	Mansfield, OH (175)	39.8

Supply Region	Demand Region	Quantity (000 Tons)
Middlesboro, KY (10) (continued)	Zanesville, OH (183)	381.3
	Charleston, SC (199)	623.0
	Columbia, SC (200)	1373.3
	Knoxville, TN (207)	817.2
	Jackson, TN (209)	175.8
	Lynchburg, VA (222)	31.0
	Richmond, VA (225)	93.1
	Wenatchee, WA (227)	217.3
	Clarksburg, WV (235)	2.0
Total		9239.7
Beattyville, KY (11)	Dayton, OH (173)	50.3
Total		50.3
Salyersville, KY (12)	Mobile, AL (5)	609.2
	Washington, DC (47)	22.2
	Savannah, GA (58)	1.1
	Muncie, IN (76)	8.4
	Cincinnati, OH (79)	1157.3
	Ft. Wayne, IN (81)	177.5
	Huntington, WV (103)	1551.2
	Dayton, OH (173)	5.4
	Dubois, PA (178)	101.6
	Wheeling, WV (181)	504.8
	Georgetown, SC (204)	152.5
	Charleston, WV (234)	224.3
	Madison, WI (240)	31.7
Total		4547.2
Pleasantville, OH (13)	Huntington, WV (103)	4069.8
	Kalamazoo, MI (125)	171.7
	Dayton, OH (173)	192.9
	Columbus, OH (176)	160.3
	Parkersburg, WV (179)	801.0
Total		5395.7
Cadinz, OH (14)	Huntington, WV (103)	226.9
	Detroit, MI (123)	436.3
	Toledo, OH (124)	202.4
	Kalamazoo, MI (125)	370.2
	Duluth, MN (129)	8.2
	Dayton, OH (173)	0.9
	Cleveland, OH (174)	2394.9
	Columbus, OH (176)	117.9
	Dubois, PA (178)	134.8
	Parkersburg, WV (179)	3259.9
	Sandusky, OH (180)	8.8
	Wheeling, WV (181)	1282.2
	Zanesville, OH (183)	2726.7
Total		11280.1

Supply Region	Demand Region	Quantity (000 Tons)
Youngstown, OH (15)	Cleveland, OH (174)	278.3
	Dubois, PA (178)	109.4
	Sandusky, OH (180)	6.6
	Wheeling, WV (181)	63.0
Total		457.3
Pittsburgh, PA (16)	Philadelphia, PA (45)	933.6
	Washington, DC (47)	92.5
	Cincinnati, OH (79)	2059.0
	Ft. Wayne, IN (81)	2433.9
	Huntington, WV (103)	1863.2
	Manchester, NH (121)	977.2
	Grand Rapids, MI (122)	2558.6
	Toledo, OH (124)	1180.5
	Scranton, PA (151)	62.4
	Rochester, NY (160)	564.4
	Buffalo, NY (162)	735.3
	Binghamton, NY (163)	28.6
	Olean NY (164)	253.6
	Cleveland, OH (174)	3198.0
	Dubois, PA (178)	924.9
	Wheeling, WV (181)	11040.8
	Pittsburgh, PA (197)	7633.3
	Nashville, TN (208)	2255.4
	Clarksburg, WV (235)	3938.3
Total		40403.5
Kittaning, PA (17)	Dover, DE (46)	393.6
	Washington, DC (47)	968.7
	Brandywine, MD (116)	629.8
	Toledo, OH (124)	20.3
	Marquette, MI (126)	209.8
	Scranton, PA (151)	1112.4
	Rochester, NY (160)	378.7
	Buffalo, NY (162)	464.4
	Binghamton, NY (163)	150.0
	Olean, NY (164)	1862.9
	Cleveland, OH (174)	75.8
	Dubois, PA (178)	3094.6
	Altoona, PA (195)	5047.8
	Harrisburg, PA (196)	2189.1
	Pittsburgh, PA (197)	11755.1
Total		28353.0
Sharon, PA (18)	Scranton, PA (151)	83.3
	Dubois, PA (178)	429.9
Total		513.2
State College, PA (19)	Scranton, PA (151)	72.9
	Rochester, NY (160)	273.5
	Binghamton, NY (163)	368.9
	Olean, NY (164)	410.2
	Altoona, PA (195)	228.5
	Harrisburg, PA (196)	958.7
Total		2312.7

Supply Region	Demand Region	Quantity (000 Tons)
Somerset, PA (20)	Philadelphia, PA (45)	72.7
	Dover, DE (46)	577.4
	Washington, DC (47)	566.5
	Hagerstown, MD (113)	238.1
	Brandywine, MD (116)	295.2
	Scranton, PA (151)	145.8
	Binghamton, NY (163)	47.2
	Altoona, PA (195)	32.6
	Harrisburg, PA (196)	341.4
	Elkins, WV (231)	2708.1
Total		5025.0
Charleston, WV (21)	Cincinnati, OH (79)	120.9
	Ft. Wayne, IN (81)	1063.7
	Huntington, WV (103)	989.4
	Toledo, OH (124)	40.7
	Duluth, MN (129)	2.4
	Raleigh, NC (166)	2516.9
	Dubois, PA (178)	2.0
	Fredericksburg, VA (224)	292.5
	Roanoke, VA (226)	113.3
	Elkins, WV (231)	253.0
	Martinsburg, WV (233)	803.7
	Charleston, WV (234)	7337.5
Total		13536.0
Clarksburg, WV (22)	Philadelphia, PA (45)	413.3
	Huntington, WV (103)	44.0
	Toledo, OH (124)	60.9
	Cleveland, OH (174)	1174.0
	Dubois, PA (178)	14.6
	Martinsburg, WV (233)	2434.2
Total		4141.0
Philippi, WV (23)	Philadelphia, PA (45)	109.1
	Washington, DC (47)	138.7
	Grand Rapids, MI (122)	127.7
	Toledo, OH (124)	34.6
	Buffalo, NY (162)	77.4
	Parkersburg, WV (179)	425.5
	Elkins, WV (231)	341.9
	Martinsburg, WV (233)	914.9
Total		2169.8
Peoria, IL (26)	Peoria, IL (65)	1478.3
	Chicago, IL (67)	72.1
	Davenport, IA (69)	475.0
	Lasalle, IL (71)	227.5
	Springfield, IL (75)	379.6
	Waterloo, A (88)	318.8
	Des Moines, IA (92)	40.8
	Green Bay, WI (237)	695.5
Total		3687.6

Supply Region	Demand Region	Quantity (000 Tons)
Taylorville, IL (28)	Peoria, IL (65)	2253.9
	Davenport, IA (69)	75.8
	Springfield, IL (75)	4987.9
Total		7317.6
Mt. Vernon, IL (29)	Peoria, IL (65)	775.1
	St. Louis, MO (70)	14916.4
	Lasalle, IL (71)	656.7
	Paducah, KY (72)	3232.8
	Rockford, IL (73)	127.3
	Marion, IL (74)	747.5
	Springfield, IL (75)	685.7
	La Crosse, WI (128)	11.0
	Cape Girardeau, MO (138)	1382.9
	Wausau, WI (23*)	59.5
Total		22594.9
Tuscola, IL (30)	Danville, IL (66)	462.4
	Rockford, IL (73)	157.3
	Springfield, IL (75)	221.7
	Indianapolis, IN (80)	6.1
	South Bend, IN (82)	1593.5
	Terre Haute, IN (84)	2655.3
	Wausau, WI (238)	180.7
Total		5277.0
Harrisburg, IL (31)	Mobile, AL (5)	1953.9
	Memphis, TM (18)	314.4
	Chicago, IL (67)	11.7
	Paducah, KY (72)	1484.9
	Marion, IL (74)	146.3
	Evansville, IN (77)	942.5
	Waterloo, IA (88)	27.8
	La Crosse, WI (128)	249.6
	Wilmar, MN (133)	21.1
	Nashville, TN (208)	1171.8
	Green Bay, WI (237)	49.2
Total		6373.2
Sullivan, IN (32)	Marion, IL (74)	287.2
	Evansville, IN (77)	98.6
	Indianapolis, IN (80)	2249.0
	Terre Haute, IN (84)	3247.7
Total		5882.5
Morganfield, KY (33)	Decatur, AL (7)	6346.6
	Memphis, TN (18)	297.9
	Atlanta, GA (56)	9.2
	Chicago, IL (67)	1206.3
	St. Louis, MO (70)	139.2
	Paducah, KY (72)	368.5

Supply Region	Demand Region	Quantity (000 Tons)
Morganfield, KY (33) (continued)	Muncie, IN (76)	81.9
	Evansville, IN (77)	8386.7
	Louisville, KY (78)	1301.0
	Cincinnati, OH (79)	1232.9
	Indianapolis, IN (80)	699.0
	Bloomington, IN (83)	2054.5
	Terre Haute, IN (84)	202.9
	Rochester, NY (160)	17.7
	Knoxville, TN (207)	482.6
	Green Bay, WI (237)	316.1
	Wausau, WI (238)	7.8
Total		23150.8
Madisonville, KY (34)	Birmingham, AL (4)	296.8
	Mobile, AL (5)	170.2
	Decatur, AL (7)	5659.5
	Memphis, TN (18)	1161.1
	Tampa, FL (52)	1111.6
	Chattanooga, TN (55)	3478.1
	Atlanta, GA (56)	442.8
	St. Louis, MO (70)	162.2
	Lasalle, IL (71)	59.4
	Paducah, KY (72)	10461.8
	Evansville, IN (77)	1262.3
	Louisville, KY (78)	3633.0
	Cincinnati, OH (79)	2470.5
	Bloomington, IN (83)	829.9
	Huntington, WV (103)	65.2
	Grand Rapids, MI (122)	1.2
	Greenville, MS (134)	29.5
	Jefferson City, MO (137)	46.0
	Wheeling, WV (181)	253.5
	Nashville, TN (208)	949.0
	Green Bay, WI (237)	142.2
	Madison, WI (240)	23.3
Total		32709.4
Mt. Pleasant, TX (38)	Shreveport, LA (22)	3535.0
Total		3535.0
Fairfield, TX (39)	Austin, TX (212)	5611.0
Total		5611.0
Poteau, OK (43)	Kansas City, MO (94)	72.6
Total		72.6
Muskogee, OK (46)	Kansas City, MO (94)	1639.2
	Pittsburg, KS (99)	157.5
	Jefferson City, MO (137)	179.0
	Springfield, MO (139)	24.0
Total		1999.7

Supply Region	Demand Region	Quantity (000 Tons)
Pittsburg, KS (47)	Kansas City, MO (94)	411.1
	Pittsburg, KS (99)	157.5
	Springfield, MO (139)	630.5
Total		1199.1
Clinton, MO (48)	Springfield, MO (139)	1798.8
Total		1798.8
Macon, MO (49)	Waterloo, IA (88)	125.7
	Des Moines, IA (92)	118.0
	Kansas City, MO (94)	0.5
	Jefferson City, MO (137)	1332.2
Total		1576.4
Mound City, KS (51)	Pittsburg, KS (99)	1475.1
Total		1475.1
Albia, IA (56)	Peoria, IL (65)	52.9
	Des Moines, IA (92)	438.3
Total		491.3
Winslow, AZ (57)	Las Vegas, NV (13)	3820.0
	Flagstaff, AZ (14)	3737.8
Total		7557.8
Gallup, NM (59)	Flagstaff, AZ (14)	7562.3
Total		7562.3
Gunnison, CO (62)	Grand Junction, CO (35)	106.2
Total		106.2
Steamboat Springs, CO (63)	Grand Junction, CO (35)	153.1
	Denver, CO (36)	2862.6
	Pueblo, CO (38)	514.5
	Steamboat Springs, CO (40)	645.1
	Waterloo, IA (88)	143.6
	Des Moines, IA (92)	61.0
	Kansas City, MO (94)	32.0
Total		4411.9
Canon City, CO (64)	Pueblo, CO (38)	41.1
Total		41.1
Greeley, CO (65)	Denver, CO (36)	34.3
Total		34.3

Supply Region	Demand Region	Quantity (000 Tons)
Rawlins, WY (66)	Denver, CO (36)	195.8
	Chicago, IL (67)	3615.6
	Omaha, NE (85)	1115.1
	Sioux Cty, IA (86)	1158.6
	Kansas City, MO (94)	479.5
	Topeka, KS (96)	1137.6
	Lincoln, NE (145)	254.2
	Milwaukee, WI (239)	761.7
	Casper, WY (241)	3218.0
Total		11936.1
Gillette, Wy (67)	Pueblo, CO (38)	1607.5
	Peoria, IL (65)	52.9
	Des Moines, IA (92)	210.6
	Huntington, WV (103)	1093.1
	Rapid City, SD (205)	182.0
	Rock Springs, WY (243)	435.3
Total		3581.5
Rock Springs, WY (68)	Omaha, NE (85)	89.3
	Rock Springs, WY (243)	3582.0
Total		3671.3
Price, UT (70)	Las Vegas, NV (13)	655.8
	Flagstaff, AZ (14)	1046.4
	Cincinnati, OH (79)	111.9
	Huntington, WV (103)	374.9
	Morgan, VT (219)	433.0
	Salt Lake City, UT (220)	508.0
Total		3130.0
Forsyth, MT (75)	Peoria, IL (65)	1187.4
	Chicago, IL (67)	11111.1
	St. Cloud, MN (127)	647.0
	Duluth, MN (129)	2612.8
	Minneapolis, MN (131)	1666.8
	Wilmar, MN (133)	16.5
	Billings, MT (140)	700.0
	Miles City, MT (143)	197.0
	Wausau, WI (238)	68.6
	Madison, WI (240)	1748.4
Total		19955.6
Stanton, ND (79)	Thief River Falls, MN (132)	679.4
	Bismark, MD (172)	3026.2
	Pierre, SD (206)	1609.3
Total		5314.9
Minot, ND (80)	Bismark, MD (172)	1750.9
Total		1750.9
Centrailia, WA (87)	Portland, OR (193)	4200.0
Total		4200.0

THE COAL AND ELECTRIC UTILITIES MODEL: A RECENT APPLICATION

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Daniel E. Klein: The Coal and Electric Utilities Model
C. Hoff Stauffer: A Recent Application for the EPA

The Coal and Electric Utilities Model

The complexity of the U.S. coal and electric utility industries poses difficult problems to the analyst who desires to forecast future conditions or evaluate the impacts of changing conditions. Uncertainties regarding numerous key issues increase the difficulties of performing such analyses. Further, conditions which affect one portion of either industry often have dramatic effects throughout both industries. Hence, attempts to analyze either industry in isolation are necessarily incomplete. To capture the full range of these interactions, ICF developed the ICF Coal and Electric Utilities Model (CEUM). The model is intended as a supplement--not a replacement--to more traditional methods of analysis.

The ICF Coal and Electric Utilities Model is based upon the National Coal Model (NCM), an earlier model developed by ICF for the Federal Energy Administration (FEA). This model was in turn based upon the coal supply component of the Project Independence Evaluation System (PIES) model, also developed by ICF for FEA. The ICF Coal and Electric Utilities Model, however, is now substantially different from the National Coal Model. Many structural alterations, parameter changes, and overall enhancements have been made to the ICF Coal and Electric Utilities Model since it originated from the National Coal Model. At each stage in the evolution of the CEUM, greater detail, sensitivity, and flexibility have been added. The numerous analyses for which the CEUM has been used have provided valuable insights to key decisionmakers in both government and industry, and have served as the basis for continuing model development.

This summary briefly describes the capabilities, basic structure, and key characteristics of the CEUM. A more detailed description may be found in: ICF Incorporated, Coal and Electric Utilities Model Documentation, July, 1977 and in subsequent reports of analyses using the model.

CAPABILITIES

The CEUM was designed to provide the capability to analyze a wide variety of issues that relate to coal and electric utilities. Such issues arise for both public and private sector clients. Some examples are:

> Coal prices -- How are the prices of different types of coal from different supply regions likely to change? How will this vary with altered conditions?
>
> Coal production -- What would be the impact on regional coal production levels of alternative reclamation requirements or of different rates of increase in coal industry wages?

Coal demands -- Where are increases in coal utilization likely to occur? For which types of coals? What will be the requirements on coal carriers? What will be the costs?

Western coal development -- How much coal might be produced in the western states? How will this be affected by sulfur emission standards, electricity growth rates, transportation rates, federal leasing policies, state severance taxes, synthetic fuel development, and/or new technologies?

Clean Air Act Amendments -- What would be the effect on regional coal production, electricity costs, and utility oil consumption of alternative new source performance standards or revisions in existing state implementation plan (SIP) regulations?

Powerplant and Industrial Fuel Use Act conversion orders -- What would be the impact of converting power plants from oil or gas to coal? What would be the effects of banning new oil and/or gas plants? What would be the effect of banning existing oil and/or gas plants from baseload generation?

Power generation technologies -- What is the outlook for different technologies for power generation or pollution control? Given emission regulations and coal industry conditions, is dry scrubbing an option, and if so, for whom and for which coals? What new technologies will fit into future coal and utility industry conditions?

Taxes -- What would be the impact of a change in tax laws applicable to either the coal or utility industries (e.g., elimination of the percentage depletion allowance or an increase in the investment tax credit allowable)?

The model also provides the capability for analyzing possible impacts of external conditions which affect both the coal and electric utility industries.

Cost changes -- What are the impacts of changes in factor prices including the cost of capital?

Physical constraints -- What are the impacts of constraints on equipment, miners, or transportation facilities?

Fuel price and availability -- What are the impacts of changes in oil and gas prices, and their availability to the utility sector?

Utility plans -- What are the impacts of changes in planned generating capacity additions, including changes in the rate of nuclear capacity additions?

Electrical load -- What are the impacts of changes in the growth rate of electricity consumption or in the shapes of load duration curves?

New technologies -- What are the impacts of commercial development of new technologies (e.g., synthetic fuels, form coke, and MHD)?

The model provides the ability to forecast key attributes of the coal and electric utility industries by year and by region. For the coal industry, forecasts can be made of consumption by sector, production by method of mining, supply prices, coal distribution and transportation costs. For the electric utility industry, forecasts can be made of generation, capacity utilization, capacity expansion, pollution cost and equipment, emissions (for SO_x, NO_x, and TSP), fuel use (including coal by type), electricity transmission, rate impacts, and costs for capital, fuel, O&M and pollution control.

MODEL STRUCTURE

The basic CEUM structure is straightforward. A supply component, via a transportation network, provides coal to satisfy the demand from both utility and non-utility consumers at least cost. In so doing, coal production, consumption, and price are established and reported by region, consuming sector, and coal-type. Figure 1 outlines the basic structure of the CEUM and shows how the major components interrelate.

The CEUM generates an equilibrium solution through a standard linear programming formulation balancing the supply and demand requirements for each region's coal-types. The objective function of the linear program is written to minimize total delivered costs. The model determines the levels of nearly 20,000 individual activities covering in great detail the full scope of the coal and electric utility industry. These include the building and operating of different types of mines and powerplants, the transportation of coal by different modes, and the interregional transmission of electricity. Approximately 3,000 constraints complete the model by providing a comprehensive structural and economic framework for the solution. These constraints represent such factors as limits on reserves available for mining, long-term coal contracts, SIP emission limitations, transportation and transmission capacities, and powerplant construction plans.

Supply Component

The supply component offers a variety of coal-types (i.e., 40 different possible combinations of five Btu and eight sulfur categories) from 30 geographically dispersed supply regions. Table 1 gives the definitions for the various categories of coal and shows the distribution of the coal reserves to CEUM coal-types. The BOM Demonstrated Reserve Base data are used in CEUM except for selected areas (e.g., Texas, Campbell County in

FIGURE 1

STRUCTURE OF THE ICF COAL AND ELECTRIC UTILITIES MODEL

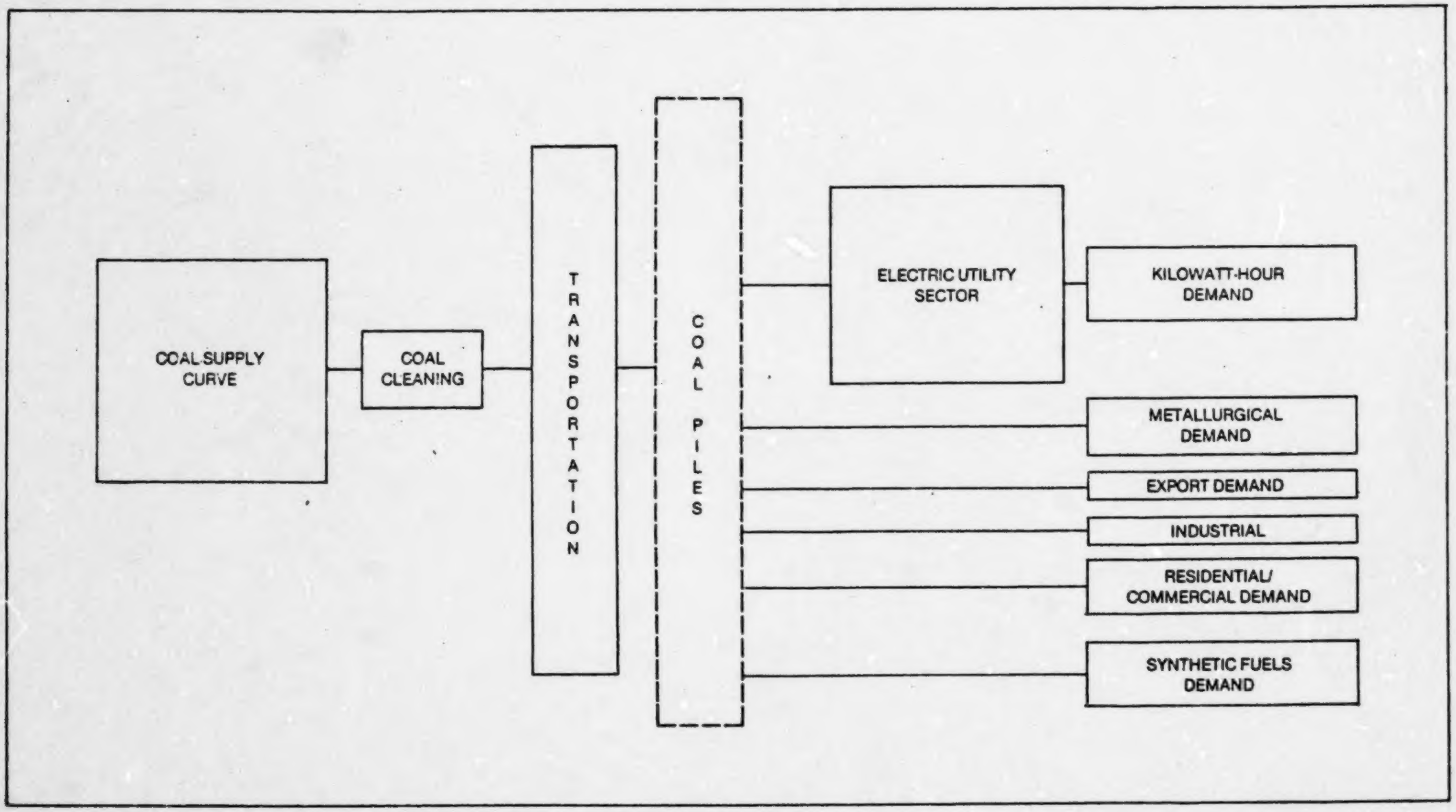

COAL SUPPLY CURVE
COAL CLEANING
TRANSPORTATION
COAL PILES
ELECTRIC UTILITY SECTOR
KILOWATT-HOUR DEMAND
METALLURGICAL DEMAND
EXPORT DEMAND
INDUSTRIAL
RESIDENTIAL/ COMMERCIAL DEMAND
SYNTHETIC FUELS DEMAND

TABLE 1

CEUM COAL RESERVES INPUTS BY CEUM COAL-TYPES

(10^9 Tons)

Btu Levels (10^6 Btu/ton)	Code	Sulfur Content Levels (pounds sulfur/10^6 Btu) 0.00-0.40 A	0.41-0.60 B	0.61-0.63 C	0.64-0.83 D	0.84-0.92 E	0.93-1.67 F	1.68-2.50 G	2.50+ H	Total
Over 26	Z	0.7	16.0	1.1	6.6	2.0	14.2	7.0	0.0	47.6
23-25.99	H	2.3	5.6	0.3	2.1	1.3	9.7	34.4	2.4	58.1
20-22.99	M	1.6	6.8	2.5	5.0	0.0	2.3	19.5	123.5	161.2
15-19.99	S	82.4	51.6	0.0	31.0	0.0	18.0	0.2	0.7	183.9
Under 15	L	0.6	0.1	0.0	6.6	0.0	10.8	4.1	0.0	22.2
Total		87.6	80.1	3.9	51.3	3.3	55.0	65.2	126.6	473.0

NOTE: The classification of the BOM demonstrated reserves to Btu and sulfur levels is based upon the average seam values by county as reported by the Bureau of Mines on their demonstrated reserve base data tape. The sulfur content of all bituminous coals has been reduced to account for assumptions regarding the level of coal preparation. In CEUM, these BOM reserve values for certain areas (e.g., Texas, Campbell County in Wyoming) have been modified based upon subsequent ICF analyses, and are reflected in the above totals. Not included in the above totals are reserves tonnages reported on the BOM reserve base data tape but not associated with Btu and sulfur values; in CEUM, these tonnages are allocated proportionately to the coal-types in the respective regions.

Price-sensitive "supply curves" have been developed for each region's coal-types as a function of coal reserves data and mine-engineering costing algorithms. Each coal supply curve is represented as a step function, with steps for existing as well as potential new mines. Reserves which are not committed to existing production and are not illegal to mine are allocated among representative mine-types. The length of each step represents the amount of coal available from that type of mine. The height of the step represents the minimum price the producer would accept for the coal given his required rate of return. See Figure 2 for an example supply curve. There are about 200 supply curves in the model, each representing a specific coal-type in one of the 30 coal supply regions.

The costs of producing all bituminous coal includes charges for a moderate level of coal preparation for bituminous coals, and a more elaborate level of preparation for metallurgical-grade coals. Coal preparation entails a weight yield, Btu yield, capital and O&M cost, and reduction in pounds sulfur per million Btu. The model also has the option of deep cleaning (i.e., extensive preparation) at increased costs for two reasons: (1) to meet a standard of 1.2 pounds sulfur dioxide per million Btu, or (2) to meet a typical one percent sulfur emission limitation for existing sources.

Coal Transportation

The transportation component of the model transfers the coal from the supply regions to coal piles in the demand regions. The coal is assumed to be shipped from a central location in each supply region over a specifically defined route to a central location in the demand region. The cost of transportation is a per-ton charge based upon forecasted rates for unit-train or barge shipments. In the case of unit trains, ICF keeps abreast of ICC decisions and incorporates assumptions regarding ratemaking policy in the forecasts. Other transportation modes such as slurry pipelines have been included for specific analyses. Lower bounds are used to represent the effects of specific known long-term commitments, while upper bounds may be used to represent bottlenecks.

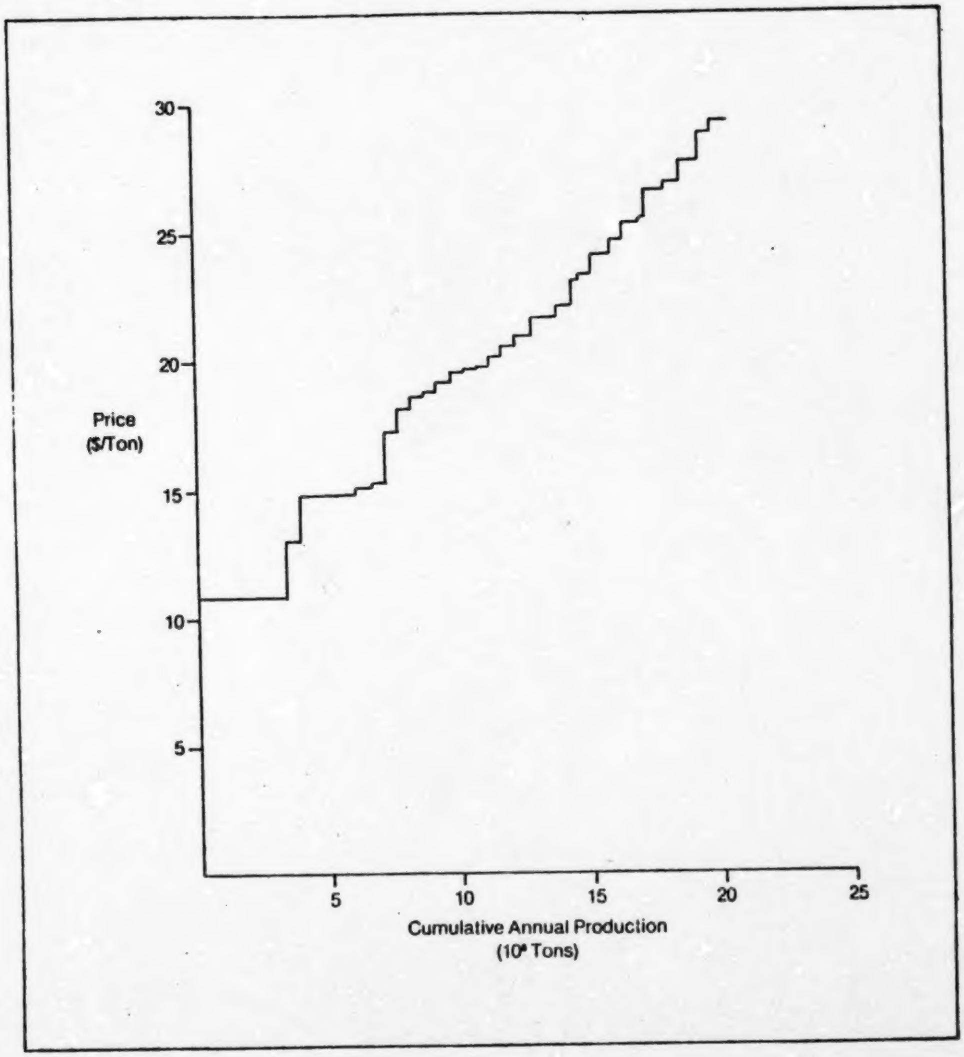
Coal Piles

Coal piles are an analytic construct of the CEUM, provided to reduce the overall model to a manageable size. Instead of tracking all the different coal-types from the supply regions to the final consumer, the coal is transported to piles in each demand region. Each pile is identified by rank and sulfur level.

Each coal pile holds a single rank of coal (e.g., either bituminous--the three highest Btu categories; subbituminous--the second lowest Btu category; or lignite--the lowest Btu category) and a single sulfur level. Six sulfur levels are used, eliminating the two sulfur levels from the supply sector which exist to provide the model the capability to deep clean (to meet New Source Performance Standards or a one percent sulfur emission limitation for existing sources). If the model chooses not to

FIGURE 2

EXAMPLE COAL SUPPLY CURVE



deep clean these coals, they are placed in the next highest sulfur category. In addition, a special pile was designed to satisfy metallurgical demand which includes only the highest Btu content coals with the four lowest sulfur levels.

For a given sulfur level and rank of coal, each pile accumulates coal as Btu rather than tons. Coal is mined and transported as tons and burned as Btu. The coal is transformed from tons to Btu in the coal piles. Within each demand region, the consumption demands for coal by sector (utility, industrial, residential/commercial, metallurgical, export, synthetic fuels) are satisfied by drawing Btu (not tons) from each of the appropriate coal piles.

Utility Sector

The utility demand component begins with the estimation of electrical energy sales (in kilowatt hours). Forecasts of electrical energy sales by region are calculated by multiplying historical consumption by annual future growth rates for each region. For each region this estimate is then split among four load categories: base, intermediate, seasonal peak, and daily peak. The CEUM then determines the least-cost method for generating and distributing electricity for each of these load categories. On the basis of minimizing the cost of generating and distributing electricity, the model determines the extent to which (1) existing powerplants of various types are operated in each load category, (2) new plants of various types are built and operated in each load category, and (3) electrical power is transmitted between regions. Steam, internal combustion (e.g., combustion turbines and diesel engines), and combined cycle powerplants may be used. Fuels include coal, oil, gas, nuclear, and hydro as appropriate. Other types of powerplants or new technologies (e.g., liquefaction and gasification) can be readily accommodated.

The model explicitly accounts for the impacts of differing levels of environmental standards. To meet sulfur emission limitations, the model can (a) burn a single coal-type that meets standards, (b) burn an appropriate blend of low, medium and high-sulfur coal that meet standards, or (c) install a scrubber (full or partial, wet or dry) depending upon the types of air quality regulations which apply to specific types of plants in each region.

Non-Utility Coal Demand

The non-utility coal component consists of the metallurgical, export, industrial, residential/commercial, and non-utility synthetic fuels sectors. The CEUM seeks to satisfy these at minimum cost. This is done by drawing the required coal from the appropriate coal piles or as a specified blend from several coal piles.

Estimates are made outside the CEUM for regional demand for coals of specific heat content and sulfur level in each of the non-utility sectors. Such estimates are based upon careful and detailed analyses of each of the sectors and are frequently updated as more recent information becomes available. These analyses consist of ICF studies (on such topics as coal exports or metallurgical coal demand), the results of other models (e.g., ICF's Industrial Boiler Fuel Choice Model), or sound analyses performed elsewhere.

These estimates are developed outside of the CEUM as each only constitutes a very small, though important, fraction of the market for coal. Some of the non-utility demands are not price sensitive as to quantity used; price merely indicates supply sources. Further, coal demands in some of the non-utility sectors are not readily amenable to modelling analyses of sufficient reliability because they are not so much a function of Btu and sulfur content as of other characteristics. The increased modelling complexity required for their explicit estimation within CEUM would not be offset by new insights gained about the coal markets beyond those obtainable by thorough outside analyses.

KEY CHARACTERISTICS OF CEUM

The CEUM has six key characteristics:

1. It is usable because it provides insights and presents useful results;

2. It is understandable because it is based upon engineering and accounting relationships, not hypothetical econometric relationships;

3. It is flexible allowing for changes in assumptions and data inputs;

4. It generates equilibrium solutions which balance supply and demand by region and by coal-type, at a price;

5. It has a high degree of resolution with 30 supply regions, 39 demand regions, 40 coal-types, and six consuming sectors; and,

6. It is price sensitive, yielding projections of FOB (freight on board) mine prices by production region and coal-type and CIF (cost including freight) plant prices by consuming region, sector, and coal-type.

Each of these attributes is discussed in greater detail in the following paragraphs.

Usable

A model is only usable if its users can understand the results and draw cogent, reliable conclusions from them. The CEUM was specifically designed, and has been used many times, to provide the insights necessary for decision making. Each of the key characteristics described below contributes to its usefulness. Use of the model requires a great deal of care in both the preparation of analyses and the interpretation of results. ICF's staff is highly experienced in developing analyses using the model and in interpreting the significance of the results.

The CEUM output has been developed to provide analysts useful information at levels of detail required for many types of analyses. A wide variety of reports of conditions in the coal and electric utilities industries are available. Production-related output is reported by: (1) 30 CEUM supply regions, (2) 12 aggregations of supply regions, (3) four broad geographic regions, and (4) national totals. Consumption-related output is reported by (1) 39 CEUM demand regions, (2) nine aggregated demand regions, (3) three broad geographic regions and (4) national totals. For production and consumption outputs, each of these regional values can be further disaggregated by coal-type, mining method, consuming sector, etc. The reports also provide analysts with historical data to place the model results in better perspective.

Understandable

The model design is based upon engineering relationships. This allows the components of the model to be easily understood, checked, and revised.

The model does not deal with abstract concepts but with measurable quantities or relationships. It breaks complex relationships into their component parts and then uses the best estimate possible for each component. Since it is the components with which most people deal, it is the components which can be estimated best. The use of a computer allows those individual estimates to be drawn together into a large-scale system.

The inputs required by the model are either drawn from existing data or are assumptions about future conditions. In either case, data inputs require precise specifications in great detail for a larger number of factors. Many critical gaps in the available data exist. Just as the real world must make business decisions with imperfect information, so necessarily must this (or any) model forecast with imperfect information. The strength of the structural approach employed by CEUM is that it requires the gaps in knowledge be filled carefully and explicitly; it forces the analyst to evaluate key issues and permits an understanding of the relative criticality of incomplete information.

The CEUM does not bury such issues in a mountain of indirect statistical measures. The structural approach of CEUM allows the reasonability and impacts of each assumption to be directly evaluated. As more precise information becomes known, it can be readily incorporated into CEUM.

Finally, the model generates a cost-minimizing solution through a standard linear programming formulation. Analysts using the model do not have to puzzle over the interpretation of a complex heuristic which may or may not be optimal. A linear programming model is a well-understood modelling technique which introduces well-understood biases (e.g., the assumptions of linearity, marginal pricing, and non-random behavior). Constraints can be introduced into the L.P. framework to force non-optimal behavior explicitly.

Flexible

The CEUM provides a great deal of flexibility in that analyses can be performed both in terms of the time frame to be studied and the data to be utilized. Many issues have short-, medium-, and long-term implications. The short-term is defined here to be between now and five years out. Within that time horizon the capital stock of the coal industry and major consuming sectors currently exists or is already planned. Beyond 10 years, yet-to-be-planned mines and combustion facilities will comprise a significant portion of the projected capital stock. Between five and 10 years out, the constraints on capital stock and other factors become less and less binding. The model is designed primarily to forecast mid-term and long-term conditions. In shorter-range time frames, non-modelling analyses are often appropriate because so much is already determined.

Medium-term runs are characterized by the large number of constraints placed upon the model. For example, limits can be placed on the new mine capacity that can be developed within a region. Utility generating plant additions and new transmission lines can have upper bounds. Coal shipments can be given lower bounds to lock in the existing long-term contracts. Long-term model runs do not need as many constraints because the lead time is available to plan and open those mines, powerplants, and transmission lines which optimize the entire system.

The definitions of regions, consuming sectors, or coal-types can be changed within the data base alone. The CEUM can be run for different case-years by simply changing the data inputs. This flexibility enables users to tailor the model to the particular analysis to be done. For example, if the model is comparing the costs of alternative fuel types for a particular system, the demand regions could be redefined to make the utility system in question a region by itself. This would allow load curve factors, existing capacity characteristics, and coal transportation costs to be developed with greater precision.

Equilibrium Solutions

The model generates a least-cost equilibrium solution through a standard linear programming formulation which simultaneously balances supply and demand requirements for each region of the U.S. This equilibrium solution reflects a wide variety of conditions affecting both the coal and electric utility industries, including both governmental policies and non-governmental factors. The results are summarized regionally in terms of production, consumption, and prices for coal and capacity expansion and dispatch for utilities. These provide the basis for estimating other impacts such as capital requirements and environmental effects.

The equilibrium solution is important for three reasons:

1. It defines the interaction of coal supply and demand, not simply the estimating of the shifts that may occur in either supply or demand alone. Governmental actions and market conditions affect both the supply of and demand for coal and, consequently, the point of interaction of these two processes. Factors affecting supply include changes in tax laws, transportation costs, reclamation and safety regulations, and federal

leasing strategies. Factors affecting demand include changes in air pollution regulations, electricity demand, government sponsorship of new conversion technologies, and oil prices and regulations.

2. It shows regional changes. These can only be determined by the balances estimated by an equilibrium solution. Conditions in the coal and utility industry will not only affect aggregate levels of supply and demand but will affect the regional distribution of both. The recent growth in coal mining west of the Mississippi is a result of the Clean Air Act Amendments of 1970. The Amendments of 1977 further changed this picture.

3. It provides direct estimates of long-term market adaptations. In examining the long-run implications of any change in market conditions, the focus should not be on temporary perturbations, but rather on permanent adjustments. In the short-run, the ability of the coal and utilities industries to respond to changing conditions is limited; there is only so much coal production and generation capacity. The characteristics of this capacity are already determined. In the long run, both industries may adapt by shifting or expanding their capacity or modifying their demands for inputs. From the perspective of a long-run analysis, it is the path of these adaptations which is important.

Resolution

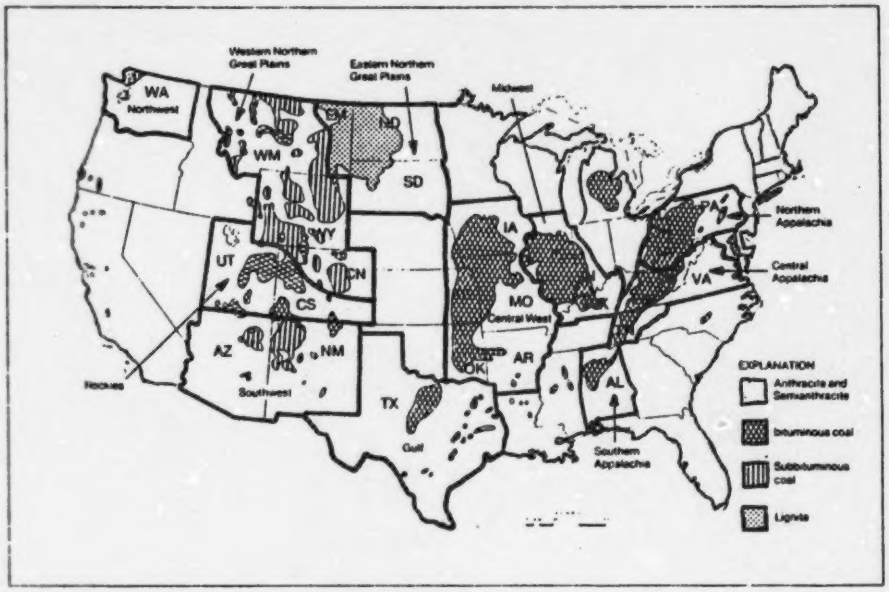
The model provides a great deal of resolution both in terms of geography and coal characteristics. The CEUM has 30 supply regions--one for each of the 26 states with substantial reserves and two for West Virginia, Kentucky, Montana, and Colorado. The model also has 39 demand regions. Figures 3 and 4 present maps of the supply and demand regions used in the model.

This high level of resolution is extremely important to model correctly the coal and electric utility industries. Conditions vary widely throughout the country in both industries. Coal-types, methods of mining, mining costs, transportation modes and rates, generation capacity types, and competitive fuel prices each differ substantially in different regions. Further, there are large differences in state laws concerning the mining and utilization of coal. All these variations argue for a great deal of disaggregation, such as that presented in the CEUM.

As a result of this geographic disaggregation, the model is able to forecast with greater accuracy shifts in the regional distributions of coal production and consumption as well as changes in regional price levels. Transportation costs, for instance, have a significant influence

FIGURE 3

CEUM SUPPLY REGIONS


Western Northern Great Plains
Eastern Northern Great Plains
Midwest
WA
Northwest
EM
ND
WM
SD
WY
UT
CN
CS
IA
MO
Central West
K
PA
Northern Appalachia
VA
Central Appalachia
AZ
NM
Rockies
Southwest
TX
Gulf
OK
AR
AL
Southern Appalachia
EXPLANATION
Anthracite and Semianthracite
bituminous coal
Subbituminous coal
Lignite

Northern Appalachia
Pennsylvania (PA)
Ohio (OH)
Maryland (MD)
West Virginia, north (NV)

Central Appalachia
West Virginia, south (SV)
Virginia (VA)
Kentucky, east (EK)
Tennessee (TN)

Southern Appalachia
Alabama (AL)

Midwest
Illinois
Indiana (IN)
Kentucky, west (WK)

Central West
Iowa (IA)
Missouri (MO)
Kansas (KS)
Arkansas (AR)
Oklahoma (OK)

Gulf
Texas (TX)

Eastern Northern Great Plains
North Dakota (ND)
South Dakota (SD)
Montana, east (EM)

Western Northern Great Plains
Montana, west (WM)
Wyoming (WY)
Colorado, north (CN)

Rocky Mountain
Colorado, south (CS)
Utah (UT)

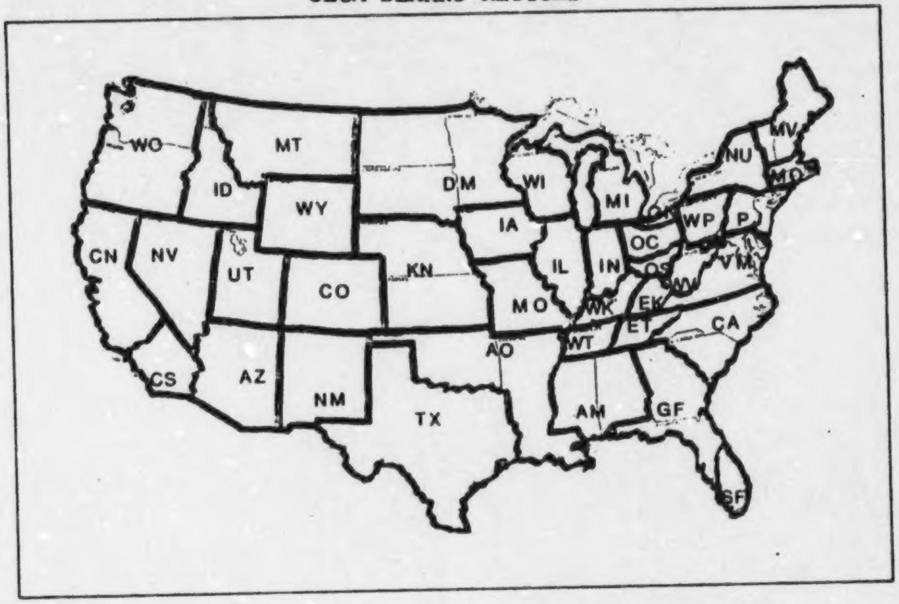
Southwest
Arizona (AZ)
New Mexico (NM)

Northwest
Washington (WA)

Alaska
Alaska (AK)

FIGURE 4

CEUM DEMAND REGIONS



New England
Maine/Vermont/New Hampshire (MV)
Massachusetts/Connecticut/Rhode Island (MC)

Mid-Atlantic
New York, upstate (NU)
Pennsylvania, east/New Jersey/New York, downstate (PJ)
Pennsylvania, west (WP)
Virginia/Maryland/Delaware/D.C. (VM)
West Virginia (WV)

Southeast
North Carolina/South Carolina (CA)
Georgia/Florida, north (GF)
Florida, south (SF)
Tennessee, east (ET)
Tennessee, west (WT)
Alabama/Mississippi (AM)

East North Central
Ohio, north (ON)
Ohio, central (OM)
Ohio, south (OS)
Illinois (IL)
Indiana (IN)
Michigan (MI)
Wisconsin (WI)
Kentucky, east (EK)
Kentucky, west (WK)

West North Central
North Dakota/South Dakota/Minnesota (DM)
Iowa (IA)
Missouri (MO)
Kansas/Nebraska (KN)

West South Central
Arkansas/Oklahoma/Louisiana (AO)
Texas (TX)

Mountain
Montana (MT)
Wyoming (WY)
Idaho (ID)
Colorado (CO)
Utah (UT)
Nevada (NV)
Arizona (AZ)
New Mexico (NM)

Pacific
Washington/Oregon (WO)
California, north (CN)
California, south (CS)

on the ability of coal to compete with other fuels. Since transportation costs for coal often outweigh the mining costs (particularly for western coal shipped long distances), it is important to portray the costs of shipping coal as accurately as possible. The precision with which transportation costs can be estimated depends on the level of disaggregation. The fewer the regions, the less precise the transportation costs.

The CEUM provides for a detailed differentiation of coal-types. Coal is not of uniform quality; its Btu content ranges from 12 million to more than 27 million Btu per ton, and its sulfur content varies from a few tenths of a percent to more than 10 times that level. One type of coal cannot be readily substituted for another. While any coal can be used to generate steam, the costs of the equipment required to burn the coal and the price of the coal itself changes with the coal characteristics.

The model tracks coal along two dimensions-Btu content and sulfur content. Coal is categorized into one of five Btu levels and into one of eight sulfur levels for a total of 40 different possible coal-types.

Price Sensitive

The CEUM develops supply curves for each coal-type within each supply region. These supply curves represent the amount of coal that can be produced at different price levels. In order that mining proceed in a logical and economic order, the least-costly-to-mine reserves are brought into production first.

As more coal of a specific type is produced, the price of that coal-type from that region increases because more expensive mines must be opened and operated and older mines may be retired. Since the supply curves for different coal-types contain different types of mines with varying amounts of available production, the rates at which prices and production increase differ between coal-types and regions. The coal-consuming sectors make choices between coal-types, producing regions, and other fuels on the basis of economic efficiency (i.e., total cost minimization).

The CEUM rigorously links the coal and electric utilities industries. It is more than just a coal model. Utility demand for coal is sensitive to many things and cannot properly be determined outside this model. CEUM provides a detailed modelling of utility coal consumption. This is crucial because electric utilities consume the major portion of domestic coal production. The electric utility sector is structured such that total generation and distribution costs are minimized. The model forecasts economic capacity expansion and dispatch. The model has the flexibility to build and operate different powerplant types in order to meet generation requirements (a key input) at least cost. The different plant-types consume different fuels--coal, nuclear, oil, gas, hydro. The model can operate existing capacity of various plant-types and/or build new capacity. Further, it can operate capacity in any of four load categories--base, cycling, seasonal peaking, and daily peaking. It will build and operate capacity of various plant-types in the various load categories such that the total of fuel, capital, and operations costs are minimized.

Different pollution control regulations (for SO_2 and other pollutants) applying to specific types of plants in different jurisdictions are explicitly modeled. Hence, consumption of any one coal-type depends on its price relative to other coal-types and other compliance alternatives. The model minimizes the total costs of generating and distributing electricity, rather than merely minimizing delivered coal costs.

Finally, the model can allow electricity transmission as an alternative to coal transportation. This means coal production in any one supply region depends on the production, transportation, and transmission costs from that region to various demand regions relative to these costs from all other supply regions.

Q. Andy Van Horn: You take into account demand in terms of long-term contracts. Can you say what the period is and does it make a difference on the price in terms of committed reserves in how long that contract period is in terms of the tonnages that are committed? Would it change things if you didn't include that as a factor in determining the price?

A. Good question. I think the contract period has to be included as a factor in formulating the coal supply curve. The question really relates to the contract length you assume and the impact it has. One curve, for instance, was formulated based on a 30-year mine life. A one-million-ton-per-year mine would commit 30 million tons of reserves over the life of that mine. Had we selected a lower value, say a 10-year mine life, a one-million-ton mine would only commit one-third as much of the reserves as before. Hence, each step would have been three times as long and you would get a much flatter coal supply curve. Over time, that effect diminishes because further off in the future, forecasts have to take into account the fact that more mines will be closing. For instance, if we have a mine opening in 1980, we maintain that mine until the year 2010. Had we gone to a 10-year mine life, that mine would have to close down in 1990 and open up a new mine. So you'd get two effects which tend to be offsetting, that is, a shorter mine life which will give you a flatter coal supply curve, but in further-out period of time you have to have that many more new mines opening up so the speed at which you go out on that supply curve chews up reserves faster.

Q. Andy Van Horn: But can't one mine have multiple contracts that would extend its life longer than the 10-year period?

A. We are talking about reserve commitments now. We are formulating our mines based on a 30-year model mine life. Some mines are shorter and some are longer. We think 30 years is a good estimate as an average. We think it corresponds well with the planned life of the electric utilities which will be the major users of that coal.

Q. Andy Van Horn: Could you say which regions of the country, if any, would be most affected by the steepness of the supply curve? I suspect in the West it probably wouldn't make that much difference.

A. Western supply curves tend to be much flatter, particularly Wyoming and Montana subbituminous coals. Midwestern high-sulfur coals tend to be flat. Northern Appalachian coals tend to be relatively flat. The steeper supply curves are primarily for the central Appalachian region low-sulfur coal. Those are the steepest supply curves which are of major importance to the model. In some small areas, such as Arkansas, you get steep supply curves but that's a function of very limited reserves. Arkansas is not projected as a major coal-producing area. In our model right now there are over 190 of these coal supply curves which represent the different coal-types. Given that there are 30 coal supply regions and 40 coal-types possible within each region, that would give you a theoretical maximum of 1,200 coal supply curves. But since many regions only have a limited number of coal-types, we have only 192 represented.

Q. Andy Van Horn: Over what region do you minimize the cost?

A. It is a national minimization. The process of doing that will also minimize it for each region.

C. C. Hoff Stauffer: The costs are added up in each of the 39 regions and then the coal supply is allocated such that the national costs are minimized. One region cannot minimize its costs further or reduce its costs further without increasing the cost in some other region by more than that amount.

C. Dan Klein: In the economic dispatch process, the model has detailed data on the existing capacities by region and by fuel types and can make trade-offs between, for instance, an existing oil-fired plant and building a new coal-fired plant to replace it. The sector can also pick up the effects of a change in oil prices, gas prices and availability, and air pollution control regulations. For the latter we have the SIPs, the old new source performance standards, and the new federal new source performance standards.

Q. Andy Van Horn: How do you average the SIPs in your demand regions? How do you determine what the SIP should be?

A. Within each of the 39 demand regions, we have up to three SIP categories. In many states the SIPs will vary on a plant-by-plant basis. We have taken the SIP data for all of the plants and aggregated or assigned it into three groups. Those groups can be defined differently from region to region. So, for instance, in the Oklahoma region, we can have a SIP category A, B, and C, and all of the plants in Oklahoma -- all of the existing coal-fired plants -- will be assigned to one of those three categories.

C. C. Hoff Stauffer: What you just said was correct. As a process of reviewing EPA's information and what the SIPs actually are, there are now some regions where we actually have five categories. Similarly, there's another category of plant called the new source performance standards category of plants that comes out somewhere between '76-'77 and 1983. They generally will be subjected to a single federal 1.2 standard, but in some states there are other standards and we can have one, two or three categories of those. On the new plants, what we call the "BACT" plants, there's a federal standard, but there also can be a more stringent state standard. And further, you can have a third category to account for things such as non-attainment, PSD, and visibility.

C. Dan Klein: What Hoff just said is a good indication of what we were saying earlier about the level of effort we put into enhancing the data that goes into this. As it turns out, the federal EPA had one idea of what the SIPs in the various states were. The regional and state EPAs had very different ideas of what the applicable SIPs were, and the utilities had still another idea. In many cases the differences were not trivial and would have an impact on one's long-term forecast. As part of our data collection and maintenance effort, we made calls to the various levels of EPA and to the utilities to try to reconcile all of these differences so that what we have in our model is our best understanding of what the applicable data are for each of the regions.

Q. Charles Kolstad: A major assumption here is that coal companies, railroads and utilities behave in a competitive manner, in a cost-minimizing manner. Can you talk about what analytic justification and support you have for that assumption?

A. We assume that the coal industry is a competitive industry, and we assume the electric utilities are seeking to minimize costs. I don't think it's necessarily true that we assume that the transportation sector is competitive. That is, we have in our model transportation rates which are a reflection of what the rates presently are, plus whatever assumption you might want to apply on real rate escalation as a function of possible deregulation. So there's no implied assumption that the transportation sector is competitive, but just that there are rates, and those are the rates that are appropriate for that time frame. I think within reasonable bounds it is fair to say that the coal industry is one of the most competitive industries in the country. There have been a number of studies to try and study the competitive nature of the coal industry. Almost uniformly they come up with the conclusion that it's a competitive industry. I would also say that the electric utilities tend to be cost-minimizing bodies, one possible exception being nuclear power, which, if you just run the numbers, would indicate to be a lower cost than coal. However, there are additional constraints on nuclear power, political, social, and such, which may not be reflected in this cost comparison. Therefore our model doesn't allow a totally free choice between nuclear and coal. That is, we constrain the upper bounds for nuclear power which can be built within a given time period. Within that upper bound, it seeks to minimize.

C. C. Hoff Stauffer: I think the right thing to say about the electric utility sector is that how we model it--and how I would argue that it exists--is that it minimizes costs within regulatory constraints. Some obvious constraints are the sulfur emission limitation. Other regulatory constraints come in the form of rate increases and where they can be inadequate to allow you to finance that sort of thing shows up in the model in a capital charge rate and builds limits, and possibly escalated costs for a new capacity. I think there is substantial justification, utilities do try to minimize costs on a daily basis, though there are few buyers trying to buy least cost fuel on a long-run basis. But the part where the utilities cost minimization is with regard to new capacity is troublesome. Where economics may indicate that they ought to build they don't because they are not able to get the rate increases they need to enable them to finance it. This is an issue that we pay very careful attention to. That, by the way, is a major energy policy issue of our current time.

Q. Charles Kolstad: You may very well be right. I'm asking this because it's a major assumption difference between your model and other models. Are there people who have tried to actually answer that question rather than assuming that's the way it is?

Q. C. Hoff Stauffer: With regard to coal costs or what?

Q. Charles Kolstad: I think the crucial thing is whether a utility will select its coal source and perhaps its plant type in a cost-minimizing manner. That's the question I'm asking about.

A. C. Hoff Stauffer: I would say yes, in the long run, they will. In the short run, you can get what seems to be bizarre behavior because of various regulatory constraints. Secondly, you can get what seems to be bizarre behavior due to uncertainty. What we are really saying is that we don't know what these costs are. We do know that the distributions overlap. We may choose the one that seems uneconomic. I would argue that you can probably find support for that type of decision in state regulatory proceedings.

Q. Andy Van Horn: Have you run your model for a current year in order to compare your results with current or past data?

A. C. Hoff Stauffer: Let me answer that one because I like that one. That would not be a useful exercise because our model, and many of the other long-run models, model the investment decision.

Investment decisions are made as a function of operating costs and prices. To run it on a current year, you have to go back to the investment decision horizon five or seven years ago and assume what the decision makers thought the costs and prices were going to be. You could not do it on what they turned out to be. So that means this is, in essence, backcasting. Trying to forecast the current or recent historical years is no easier than trying to forecast the future because when those people made investment decisions they were not considerate enough to write down what they thought the prices were going to be. Therefore, I think that exercise, in a structural model, is not a useful one. It can be done in an econometric model because you develop the econometric equations based on historical data. In a structural model, it's an interesting exercise but not clearly relevant. The last time I said this, somebody got up and said, "Well, it would be interesting to model what they did and model where they ended up and try to figure out what they must have been assuming." And I guess yes, that is interesting. It could be done that way.

C. Dan Klein: As a follow-on note to that, if you were to do this exercise, i.e., backcast seven years or ten years, you would probably be assuming $3.00-a-barrel oil, and I think that would give you a very different answer than if you used current data.

C. Lowell Smith: I would like to comment on the prior discussion of whether utilities actually minimize costs or not. First of all, I think we ought to recognize that the mandate that utilities overwhelming say they are responding to is that of providing a secure supply of electricity. Therefore, security is very high on their priority list, much higher than cost. Secondly, they are in business to make a profit, not to minimize costs. That also has to appear high on their priority list. Whether one can go back to state utility records, to emission records, and find out how well regulated they are is an exercise several people attempted to do. My impression from reading the literature is that state utility commissions are too understaffed to properly regulate the companies they are responsible for. Therefore, the proposals that the utilities bring to the utility commissions are not well reviewed from a regulatory perspective. Therefore one might infer that utilities are able, at least to a major extent, to maximize profits rather than minimize costs. Now, a point of interest that I want you to respond to. It seems that the recent literature is suggesting that there is a concentration of economic interest in the West. Coal supply regions in the West, particularly in the Powder River Basin where a large fraction of reserves are held by a few companies and which is served by only a couple of railroads, it seems that if you have regulations which tend to make this particular coal a very desirable coal then there is an opportunity for companies to extract rent out of the situation. How does your model distribute that rent with respect to the coal producers and the coal transporters.

A. Dan Klein: I'm not sure I agree with your assertion that there's a concentration of holdings in the Powder River Basin. I think the criteria depends on how many companies you see as being necessary to constitute a concentrated market. There are at least ten, and probably more than twenty companies which have fairly substantial production capabilities in the Powder River basin. Also, you have to take into account that the reserve holder with the greatest concentration, who can expand substantially upon this competitive constraint, is the federal government through its leasing policies. Also, you would have to bear in mind that the Powder River Basin, even if its coal is desirable, is not unique in terms of the national picture. That is, a utility in Texas is seeking to minimize its total electricity generation cost given all the applicable transportation costs, production costs, air pollution standards, etc. Although the Powder River Basin may be a desirable source of supply, it's not the only source of supply. That Texas utility could investigate Texas lignite, the Midwest, the Rockies, or even the Southwest as a source of supply. I think, on the coal supply side, that the companies in the Powder River Basin see themselves as being in a highly competitive situation. Transportation is a different matter. I think there are economic powers that the railroads now hold, and depending on what the federal government does with rail route deregulation, coal slurry pipelines, and other policies, that economic power could be increased or decreased. In addition, I think several of the states have powers. State and environmental groups may have powers, and at times you can see them, in a sense, taking their economic rents. A state severance tax or a strict reclamation law may be an exercise of economic rent.

Q. Lowell Smith: My recollection is that four or five coal companies own about 40 percent of the reserves and actual current production in the Powder River Basin. If you are really trading off how much it costs to scrub local high sulfur coal versus long-distance transportation of low sulfur Powder River Basin coal and a small number of companies have a semi-monopoly on the transport of that coal, how does your model account for them being able to extract economic rent from the transport from a utility who wants to compare costs of coal against installation of higher-cost scrubbers for high sulfur coal?

A. C. Hoff Stauffer: The model does not attempt to predict the behavior of the Interstate Commerce Commission. The model will allow the user to assume that. It goes in as a cost based rail rate or it can go in as a rail rate based on some other criteria. The U.S. Department of Transportation has suggested to the Interstate Commerce Commission that the proper rail rate is the one that absorbs 100 percent of the rent. The problem with that is that the rent is calculated at what specific location, at which capacity factor, or with what size boiler? What they do generally is assume a new utility is operating in base load where the so-called rent between production costs and transportation costs are substantial. If the I.C.C. would allow the railroads to absorb all of that rent, there would be no intermediate load coal plants built because coal would not be cheaper. That means the industrial sector probably would not burn coal and that you certainly would not have new coal plants built to replace oil and gas. The problem is that at any delivered coal price somebody is exactly on the margin where there is no rent and there are other people who are not on the margin where there is rent. If you adopt the preposterous policy of trying to capture all the rent, and if you do it properly so as not to screw up the allocation of energy in the country, you would have to do it on a facility-by-facility basis. I have no confidence that the Interstate Commerce Commission can do that. I think that this particular issue is one of the most important issues we are currently facing. I can't believe that intelligent people would suggest that the railroads should absorb all of those costs. The issue in the modeling sense is that I don't want to devote my resources to modeling the I.C.C. which is, in essence, what we have been discussing. Therefore, we set it up so that the user can assume what the I.C.C. is going to do. To polarize the issue you can assume that they are going to be rational or irrational and see what happens in either case.

Q. Verne Loose: For purposes of your objective function, are you using accounting costs to apply to the investment in new facilities? What costs are you using? What cost concept?

A. Dan Klein: It's the total cost of generating electricity: the capital cost for capacity, the operations and maintenance costs, and the delivered fuel costs.

Q. Verne Loose: Does that apply both to new facilities and existing facilities?

A. Dan Klein: In existing facilities the capital cost is treated as a sunk cost, and they operate on the variable cost of operation and maintenance and fuel costs.

Q. Charles Kolstad: Back to economic rent. Aren't there two types of rent, one associated with the supply curve and the other associated with location? The location rent would make a real difference to the spatial distribution of coal in the U.S. If rail companies raise the price of delivered coal so that it's a penny cheaper than the nearest competitor in the Midwest they could extract that rent. How do you capture that in a model like this?

A. C. Hoff Stauffer: You capture it with the rail rate assumption.

Q. Charles Kolstad: But it's a question that's intimately tied in with the whole LP network distribution and it's not easy to do by hand. It depends on your location and every supply curve in the rest of the country.

A. C. Hoff Stauffer: You name me what you think the I.C.C. policy is going to be. Then I think you and I together could work out a set of rates that you would feel were consistent with that policy.

Q. Lowell Smith: Let me suggest a policy. Assume before EPA's act is fully implemented that the Carter policy of deregulation is set at its maximum effect so that rail transportation becomes a free market.

A. C. Hoff Stauffer: First we would have to try to figure out how the railroads were going to react. That can be done analytically by setting the rent to capture the full rent for a new facility at base load. They are going to give up the coal demand associated with new facilities and intermediate loads and they are going to give up most of the industrial new coal demands. They are going to give up all of the replacement oil and gas coal demands. Then you can see what the revenues would be in that case. Another strategy for the railroads would be to move the rate down and say, "We'll leave it lower but go for more volume." You can calculate the price elasticity for that. I would hate to do that because I would hope that we can initially assume the federal policy was going to be more reasonable. If we can't it would be a mess.

Q. Andy Van Horn: Why is it that you say utilities would not use coal plants for intermediate loads? What other choice do they have apart from not retiring existing old plants?

A. C. Hoff Stauffer: Turbines.

Q. Andy Van Horn: Do you mean combustion turbines?

A. C. Hoff Stauffer: You can calculate the economics.

C. Andy Van Horn: I doubt, for reliability purposes, that they would want to use turbines for that amount of capacity.

A. C. Hoff Stauffer: It's perfectly analyzable because you can get the capital costs, the operation and maintenance costs, the heat rates, the high capacity factors, and the reliabilities and put all of that into the new capacity calculation and see what they come up with.

A Recent Application for the EPA

This presentation summarizes some of the work we did for the Environmental Protection Agency in support of their development of the new source performance standards for coal-fired power plants. I will briefly discuss the issues, the key alternatives, the decision, the alternatives they examined, the rationale, and the effects.

There were four sets of issues (Figure 5). One was what the cap or ceiling should be. That is the maximum emission rate that they would allow for a new coal-fired plant. There were two subissues. One was what is the specific number and that ranged between 1.2 and .5 pounds of sulfur dioxide per million Btu. The second was over what averaging period. Toward the end it focused on 24-hour or monthly but in the beginning it ranged from 3 hours to annual.

The second issue was whether there would be partial scrubbing allowed--also known as a sliding scale. The issue is whether you require all new power plants to have full control, a scrubber on all of the flue gas; or whether for certain coals, specifically low sulfur coal, you would allow less than full control.

Then there was an issue on what constituted "full control." Was that 90 percent, 85 percent or 95 percent and over what averaging period? Are washing effects to be taken into account and how is sulfur retention accounted for? The issue here is that between the raw coal in the ground and the flue gas from the power plants some sulfur gets removed. Sulfur is removed through coal preparation, losses in handling, or through sulfur retention in the ash. The issue was whether to determine full control (90 percent) based on the coal's sulfur in the ground or on the sulfur in the flue gas entering the scrubber.

Then there were issues concerning the cost of scrubbing. We examined four sets of alternatives where basically the only variable that changed was the cost of scrubbing. First, partial scrubbing was very expensive, then it was very cheap, then it got more expensive, and at the very end it got cheap again.

They decided that for coals greater than three pounds of sulfur per million Btu (Figure 6) you would have to remove 90 percent. You could have a maximum emission rate of no more than 1.2 pounds of sulfur dioxide per million Btu, i.e., that the 90 percent solution is the classic full-control alternative. Both the 90 percent and the 1.2 pound maximum emission rate are to be averaged on a 30-day running average using continuous monitors. Washing credits are allowed.

If you burn coal with less than one pound of sulfur per million Btu you are allowed to use what they call "variable scrubbing" where you have a minimum 70 percent removal and maximum emission rate of .6. This would allow use of dry scrubbing which, as we will see, was estimated to be cheaper. If you wanted to be bound by a 0.6 maximum emission rate you could remove less that 90 percent. That was the decision.

Figure 5

ISSUES

The Cap or Ceiling

- -- the number (1.2--0.5)
- -- the averaging period

Partial scrubbing or sliding scale

- -- full control (i.e., 90 percent removal)
- -- less than full control on low sulfur coals (30 to 70 percent)

Definition of full control

- -- the number (85 to 95 percent)
- -- the averaging period
- -- washing credits

The costs of scrubbing

- -- wet scrubbers
- -- dry scrubbers

Figure 6

NSPS -- THE DECISION

Sulfur in Coal (lbs. S per 10^6 Btu)	Minimum Percent Percent	Maximum Emissions Rate (lbs. SO2 per 10^6 Btu)
3	90	1.2
1-3	70-90	0.6
1	70	0.6

30 day running average (continuous monitors)

Washing credits allowed

They did agree to provide for washing credits if you were going to full control. (Figure 7) You had to remove 90 percent of the sulfur in the coal at the mine; not as the flue gas entered the scrubber. That seemed to be a good deal but when you go through the algebra it turns out to be not such a good deal. For example, if you have a six-pound coal and you remove 30 percent of the sulfur through preparation, you still have to remove 85.7 percent. You double the six pounds to get the amount of sulfur dioxide. You have to remove 90 percent so that means you have to end up with 1.2 pounds. If you begin with 12 pounds of sulfur dioxide and you got out 30 percent that means you have 8.4 pounds remaining. The problem is that you've got to lower 8.4 to 1.2. That requires you to remove 85.7 percent. So while it seemed like a good deal it turned out to be not nearly as good as one would think.

They also decided that the cap would be 1.2 pounds per million Btu on a 30-day running average. It was judged that up to 22 percent of the high sulfur reserves in Appalachia and the Midwest would require more than 90 percent removal if an emission limitation below 1.2 pounds were set.

To support that cap they produced these numbers (Figure 8). The last time I made this presentation was in Denver right after the decision and I hurried through this because it is clear to anybody that these numbers do not support that conclusion. I would think that would be a little embarrassing but it's the case.

Dry scrubbing came up right at the end and EPA was quite excited about it. It appears to be cheaper, would use less water and energy, produce less sludge, and be capable of 70 percent removal on low sulfur coal and even more on high alkaline coal. As an example (Figure 9), when you have dry scrubbing you can go from an annualized cost of 2.1 mills/kwh to 2.6 mills/kwh and reduce emissions by a substantial amount. That is a 24 percent increase

Figure 7

WASHING CREDITS

Credit for sulfur removal during preparation and sulfur retention in ash can be applied against percent removal requirement

Six pound raw coal with 30 percent sulfur credit requires scrubber to remove 85.7 percent

-- $6 \times 2 = 12 \times (1 - .9) = 1.2$

-- $12 \times (1 - .3) = 8.4$

-- $9.4 - 1.2 = 7.2$

-- $7.2 \div 8.4 = 85.7$ percent

Figure 8

RATIONALE FOR CAP

UNMINEABLE RESERVES
(%)

	Ceiling (Monthly Average)			
	1		1.2	
	85%	90%	85%	90%
BOM Data				
-- Pa., Ohio, West Virginia	7	2	4	0
-- Ill., Ind., West Kentucky	22	3	5	0
NCA Data				
-- Ohio, Northern West Virginia	29	0	3	0
-- Ill., Ind., West Kentucky	31	2	4	0

Figure 9

COMPARISON OF SCRUBBER COST ESTIMATES [1/]
(1978 $'s)

	Dry Scrubbing		Wet Scrubbing	
	33%	70%	33%	70%
Capital Costs ($/kwh)	32	38	50	85
O & M (Mills/kwh)	1.3	1.7	0.8	1.4
Capacity Penalty (%)	0.5	0.5	1.0	2.2
Energy Penalty (%)	0.5	0.5	1.0	2.2
Annualized Costs (mills/kwh) [2/]	2.1	2.6	2.1	3.8
Emission Rate (lbs. $SO_2/10^6$ Btu)	.54	.24	.54	.24

[1/] On coal with 0.4 pounds sulfur per million Btu.

[2/] Sixty-five percent capacity factor, 12.5 percent capital charge rate.

in cost to get a 55 percent reduction in emission, depending on how you calculate it. When you use wet scrubbing that same 55 percent reduction increases costs 81 percent. So dry scrubbing appeared to be quite a good deal.

There are a lot of alternatives that were examined (Figure 10): various ceilings, various levels of full or partial scrubbing, with or without dry scrubbing. There were a lot. I'll summarize this later.

Figure 11 summarizes some of the key findings associated with the various alternatives. Don't worry about emissions or costs for now; I have another slide on that. The point here is the increase in oil and gas consumption. The alternative EPA selected is L. Whether you assume wet or dry scrubber costs, alternative L is near the minimum increase in oil and gas consumption.

The industry proposal was J or I. It was about the same level so you could not argue that there was a better answer in terms of oil and gas consumption. On the other hand, full scrubbing would have substantially increased oil and gas consumption. What EPA selected was among those that had minimum increases in national oil and gas consumption. They could probably show that the only standard that would have a lesser increase would be one that did not require some scrubbing of all coal. But that would be inconsistent with the Clean Air Act.

Q. Andy Van Horn: What did you assume for the scrubber lifetime?

A. I think 15 years.

Q. Andy Van Horn: Does the EPA have data to support that?

A. We made that quite explicit. That's why we raised our capital charge rate from the normal one. We moved it up about 25 percent to account for that reduced life. We asked EPA to tell us what it was. It was in the analysis.

Figure 12 summarizes costs on the vertical axis and emissions on the horizontal. Notice that the horizontal axis does not start at zero. That was done to show the differences. The vertical axis does start at zero but measures differences rather than absolute levels. If we had graphed absolute levels with emission starting at zero, we would have ended up with all of the dots falling into a very small area. So for perspective this graph expands a very small portion of a normal graph.

The alternative L was selected. Anything above it and to the right is less cost effective. To the left is more cost effective. Therefore, why didn't EPA choose F?"

Figure 10

ALTERNATIVE STANDARDS

	Dry Scrubbing*	Ceiling**	Partial or Variable Scrubbing***
A	Yes	0.8	None -- 90% Removal
B	No	1.0	None -- 90% Removal
C	Yes	0.8	.55 Floor or 50 Percent Minimum Removal
D	Yes	1.0	.55 Floor or 50 Percent Minimum Removal
E	No	1.0	.55 Floor
F	Yes	.55	.55 Floor or 70 Percent Minimum Removal
G	Yes	.55	.55 Floor or 33 Percent Minimum Removal
H	Yes	0.7	70 Percent Minimum Percent Removal
I	Yes	0.7	33 Percent Minimum Percent Removal
J	Yes	0.9	0.50 Floor or 70 Percent Minimum Removal
K	No	1.0	0.50 Floor or 70 Percent Minimum Removal
L	Yes	1.0	0.50 Floor or 70 Percent Minimum Removal
M	Yes	1.0	None -- 90% Removal
N		Not Specified	
O	Yes	1.0	.55 Floor or 33 Percent Minimum Removal

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* Dry scrubbing specified for lower sulfur coals only; wet scrubbing always assumed for higher sulfur coals.

** Specified in terms of annual average emissions rate; EPA assumes that annual average is about 20 percent lower than a 30-day average maximum limit.

*** Washing credits allowed in all alternatives.

Figure 11

SUMMARY OF NATIONAL EMISSIONS AND COSTS FOR 1995 OF ALTERNATIVE STANDARDS

Alternative Standard	National Emissions (10^6 tons/year)	National Incremental Annualized Costs (\$ 10^9/yr.-1978 \$'s)	Increase in Oil Consumption (10^3 barrels per day)	
			Wet 1/	Dry 2/
A	20.70	4.43	450	526
B	20.58	4.10	433	434
C	20.64	2.91	209	285
D	20.64	2.90	209	285
E	20.78	3.18	255	331
F	20.19	3.21	256	332
G	20.57	2.97	211	287
H	20.63	3.15	208	284
I	21.23	2.69	208	284
J	20.45	3.20	210	286
K	20.55	3.64	204	340
L3/	20.45	3.25	210	286
M4/	20.72	4.42	480	526
N	-	-	-	-
O	20.85	3.00	207	283

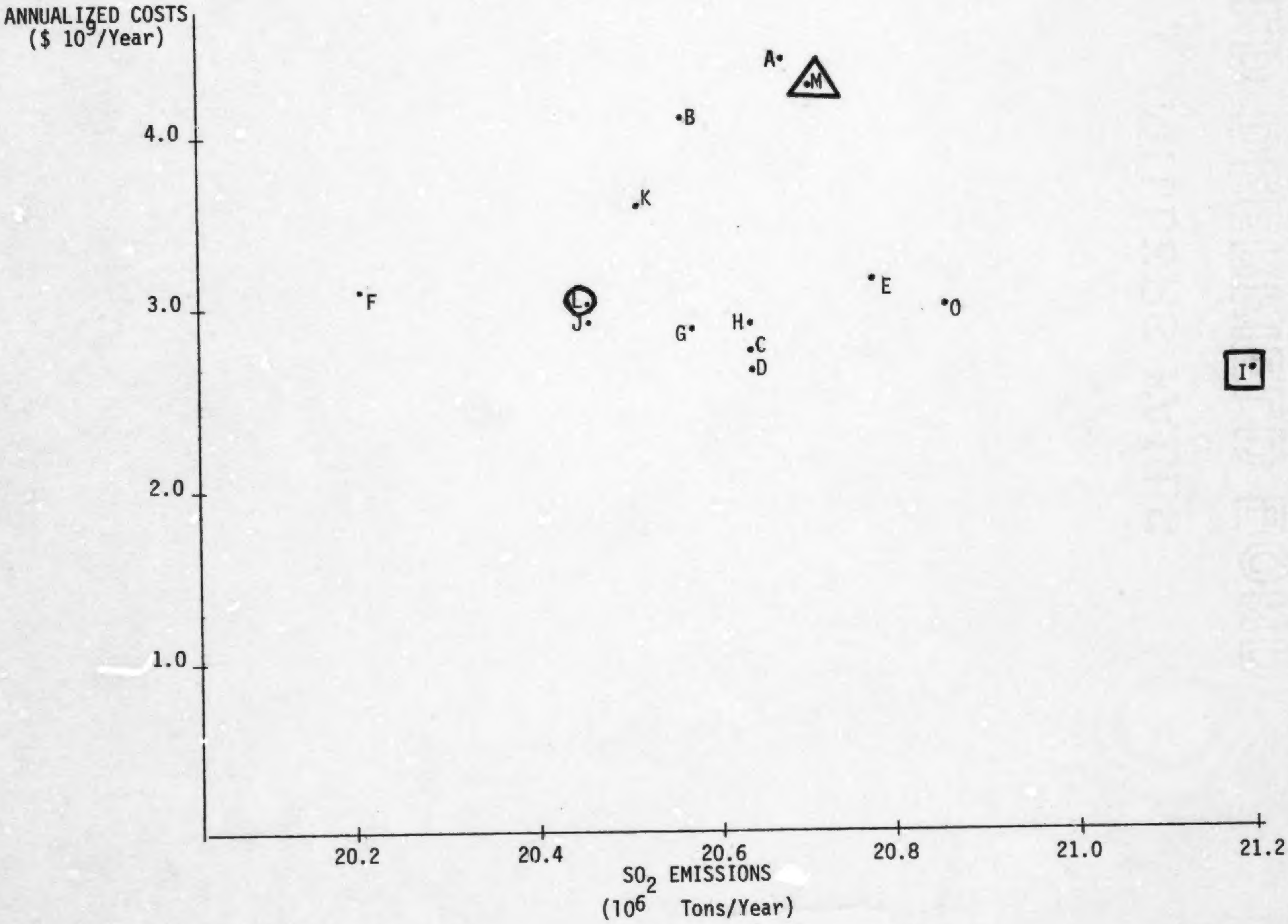
1/ From base case (1.2 pounds) using wet scrubbing costs, reported in Still Further Analyses of Alternative New Source Performance Standards for New Coal-Fired Powerplants (prepared for EPA and DOE by ICF, dated January 1979) and summarized in Appendix C.

2/ From base case (1.2 pounds) using dry scrubbing costs, summarized in Appendix C and D.

3/ This is the alternative EPA selected.

4/ This is the alternative EPA had proposed.

FIGURE 12. NATIONAL EMISSIONS AND COSTS FOR ALTERNATIVE STANDARDS IN 1995



The alternative F would have a tight cap that would affect higher sulfur coals. The industry proposal (I) was substantially dirtier but not much cheaper.

Figure 13 shows some of the details. Variable scrubbing is what EPA called their final regulation. Full scrubbing was 90 percent removal of everything and partial scrubbing is a rendition of the industry proposal. The EPA pointed out that variable scrubbing had less national emissions than either of the alternatives. That surprised people because variable scrubbing allowed more emissions from new plants. The big change in the oil and gas consumption occurs when you allow variable scrubbing. You build more coal plants but burn less oil and gas so the total emissions go down. The increase in emissions for new plants is not that great.

Q. Andy Van Horn: Would you comment on what the error bars on those individual points might be?

A. You are measuring differences. The absolute levels could change left or right. I think that just pointing out the sensitivity of these findings to dry scrubbing costs is sufficient to show that there's substantial uncertainty.

C. Lowell Smith: You might add that the result is very dependent on the retirement rate you assume for existing plants and the year you are doing the analysis for. Both are very important factors in getting that conclusion.

A. That's right. The implication is that most people will agree that existing oil and gas plants will be retiring sometime after 2000. Therefore, if you perform this analysis for 2000 they wouldn't be there to be retired early by making the new coal plants cheaper.

Figure 13

NATIONAL EMISSIONS -- 1995

(10^6 tons/year)

	Variable	Full	Partial
Oil/Gas	1.24	1.45	1.24
Coal	19.21	19.27	19.99
Existing	13.95	13.94	13.96
NSPS	2.19	2.25	2.19
ANSPS	3.17	3.08	3.84
Total	20.45	20.72	21.23

Figure 14 shows that, in terms of regional emissions, variable scrubbing ended up reducing estimates of regional emissions in the East. That's because a variable scrub plant has a maximum emission rate of .6 pounds whereas a full scrub plant can have a maximum emission rate of up to 1.2. When you replace a full scrub plant with a variable scrub plant your emissions go down.

On the other hand, in the West, because the lower sulfur coals are indigenous and cheaper, you seldom will have a new plant full scrubbing and, therefore, the variable scrub plants with a .6 rate can be higher. That was the tradeoff EPA examined very carefully because they were concerned about the increase in emissions in the West. Even though national emissions were judged to be lower, they were going to be somewhat higher in the West.

Figure 15 shows details on costs. The increase in costs were somewhat higher relative to the industry proposal. The percentage increase in total utility generation and transmission costs stay relatively small. You can do many things to the utility sector but the percentage increase in rates doesn't change very much. Our rates do not change very much on a percentage basis.

The capital cost increase relative to a base line of 1.2 is modest for all alternatives. You end up with a negative increase here, not because you save money by putting on scrubbers, but because you have increased the costs of a new plant so that the industry as a whole decides to build fewer new plants and more turbines. The costs of a new coal plant are substantially higher than the costs of a turbine so that you can actually save money on a capital cost basis even though, of course, you do not save money on a full annualized cost basis. That includes fuel.

C. Jerry Eyster: Another point is the order in which you look at each policy. If the present program limits the amount of oil used in the utility sectors, this analysis, with that in place, doesn't produce the same result. So there's a problem with what order you do the analysis of various governmental programs.

A. That's a very good point. If you assume that, as a result of national policy, oil and gas consumption went down one and one-half million barrels a day, then you don't have that capacity to swing with and all the emissions would show up in the new plants. The costs get greater because when you don't have the oil plants to trade off your cost of new coal plants build up the costs of the standard. So it's not that everything stays the same, it's just that the pressures build up on other measures.

C. Andy Van Horn: If you did get rid of oil, I would suspect that you would have increased incentive for utilities to keep existing coal plants.

Figure 14

REGIONAL EMISSIONS -- 1995

	Variable	Full	Partial
East	6.62	6.96	6.81
East North Central	5.53	5.67	5.56
East South Central	3.09	3.18	3.10
West North Central	2.44	2.27	2.50
West South Central	1.70	1.68	1.99
West	1.06	0.96	1.27
Total	20.45	20.72	21.23

Figure 15

COSTS

	Variable	Full	Partial
Increase in Annualized Costs ($\$10^9$/yr.)	3.25	4.42	3.00
Percentage Increase (%)	1.9	2.6	1.7
Present Value ($\$10^9$)	33	45	30
Capital Cost Increase ($\$10^9$)	-1	+5	-3
Cost Per Ton Removed ($/ton)	1,036	1,428	1,012

A. We have never seen coal plants retired. We see their load increased because, when you increase the costs of operating the new plants, you can shift the load back onto the old plants and their emission rates are higher yielding increased emissions. In this example it turned out that emissions barely changed but there are other runs where the emissions increased substantially.

The cost per ton removed for the industry and the EPA versions were essentially equivalent. The full scrubbing alternative was substantially higher. This is relevant to questions Lowell raised which is that in the long run you don't have these displacements. You end up with solely new coal plants and, therefore, what difference does it make? And the answer is in the amount of nuclear capacity.

Figure 16 says that the world is getting cleaner because no matter which alternative you choose you are going to get a dramatic reduction in sulfur emissions from the utility sector because the old, existing coal plants, which have relatively high emission rates will be retired and replaced by new coal plants with relatively low emission rates. Then the issue becomes whether you care more about emissions in this period, where they are relatively high, or out in the future where they are relatively low.

Figure 17 shows the effects of the standards on regional coal production. Relative to the previous standard, the variable scrubbing alternative reduced Appalachian production. The reduction came primarily out of the low sulfur coals in central Appalachia and the medium sulfur coals in northern Appalachia. There was a substantial increase in Midwestern production. There was the expected reduction in Western production although perhaps not as great as some people expected.

Q. Jerry Eyster: What assumption are you making about the retirement of coal plants?

A. This was a clear sensitivity analysis at EPA's suggestion. To make the comparison clear we retired all existing coal plants by 2010 so that all that remained were the small plants subject to the previous new source performance standards and plants subject to the new source performance standards.

Q. Jerry Eyster: Was there an analysis of the cost of keeping the existing plant alive rather than bringing on the new coal plant to replace it?

A. No, there is not that analysis. It was done by assumption.

FIGURE 16
NATIONAL EMISSION TRENDS

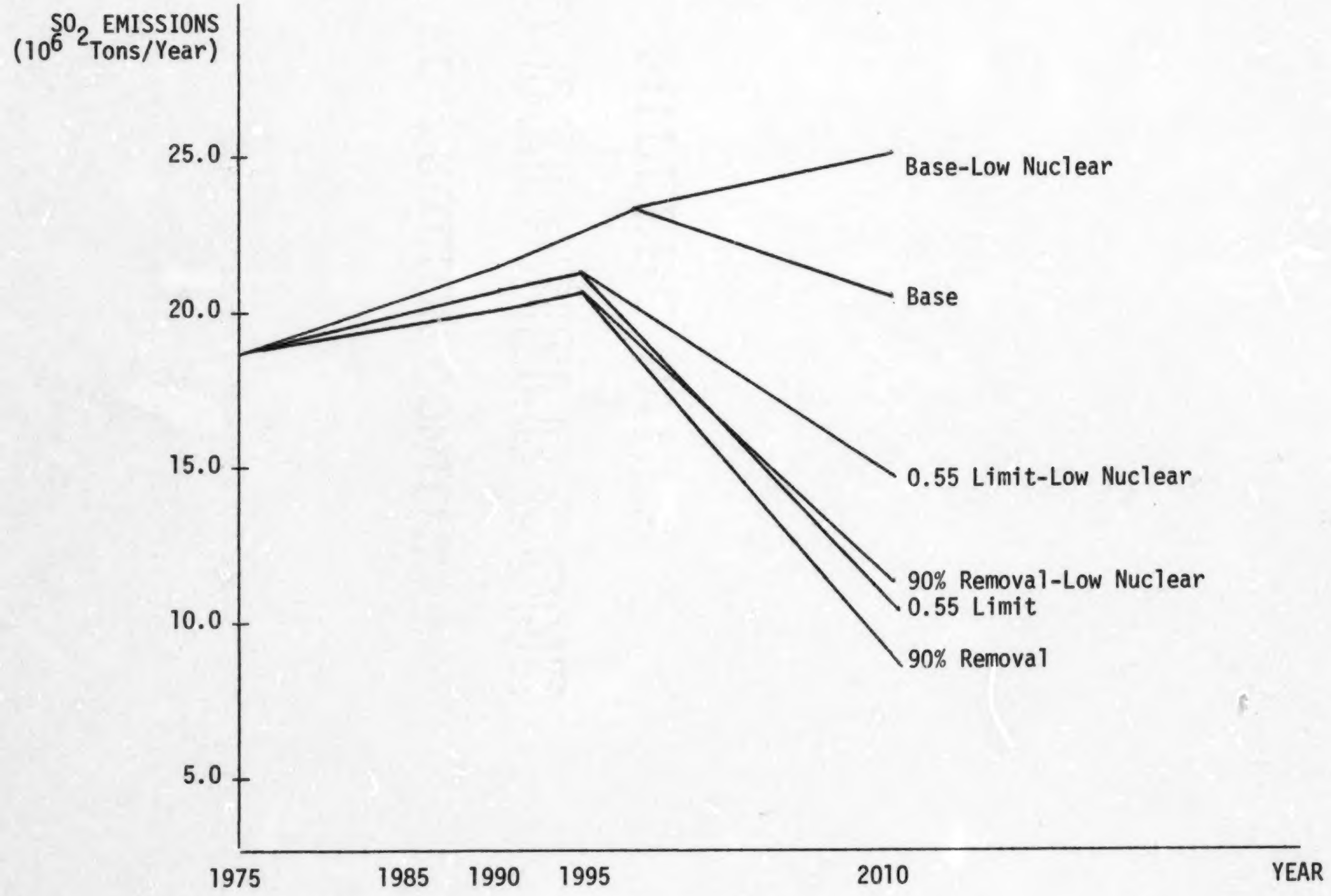


Figure 17

REGIONAL COAL PRODUCTION -- 1995

(10^6 tons/yr.)

	Previous	Variable	Full	Partial
Northern Appalachia	307	279	291	271
Central Appalachia	204	192	164	202
Southern Appalachia	13	12	10	13
Appalachia	524	484	465	486
Midwest	391	450	488	453
Eastern Northern Great Plains	35	36	35	34
Western Northern Great Plains	594	566	593	542
Northern Great Plains	630	602	628	576
Central West	7	10	9	10
Gulf	62	62	62	62
Rockies	104	94	62	107
Southwest	48	48	45	47
Northwest	2	3	3	2
Rest of West	222	217	180	228
Total	1,767	1,752	1,761	1,742
Western Coal Consumed in East	99	70	55	59

Q. Andy Van Horn: How do you decide which coal plants to retire? Does the model know when they came on line and when that 30-year period is up?

A. All the coal plants that we call existing were built before 1975. So if you have a 30-year life, that's 2005.

Q. Andy Van Horn: How would you make a projection for 2000?

A. We know the age of each of the plants and we would retire them out. You still have the problem of useful life. When we try to analyze for nonsensitivity purposes I always argue that 30 years is not the useful life; that it's longer.

Q. Andy Van Horn: What would you say is the useful life?

A. The last time we did it for an EPRI group, the group decided on 40. Nobody in the group would be willing to say that was their number, but they were all happy to say the group decided.

C. Andy Van Horn: I suspect it's actually longer for an oil plant if you believe in current utility practices.

Figure 18 shows a little bit more detail. It makes the same point as before. The reduction in Appalachia came primarily in the medium sulfur coal. There was an increase in the high sulfur coal but not enough to offset. In Central Appalachia there was a reduction in the metallurgical coals. This really means high quality, low sulfur coal. And there was not a corresponding increase anywhere else.

Figure 19 shows, for the West, a shift from low sulfur to medium sulfur coal because there was less of a premium on the low sulfur coal.

The last time I made a presentation I gratuitously offered an ICF forecast, primarily to make the point that the levels of coal consumption and production that I showed in the EPA analysis were not necessarily ones I believed but rather ones that the working group thought were reasonable. The ones I believe are substantially reduced (Figure 20). You end up with about 920 million tons in 1985 under current federal policies. That does not reflect any new energy legislation in response to Carter's initiatives. This isn't necessarily what I want to see happen, or what I think should happen, but this is what I'm afraid will happen if Congress doesn't act.

Figure 21 shows the production side of ICF's forecast.

C. Lowell Smith: The synthetics you show in Figure 20 would be drastically increased under the President's announced initiatives, probably on the order of a third to a half billion tons a year. Also, the export line reflects that we are still competitive with the Australian strip mine metallurgical coal market which events over the recent couple of years indicates we are not.

A. I don't agree. It does not reflect metallurgical exports. As a matter of fact, we show them dropping in 1985. This increase beyond 1985 is in steam exports to Europe. The President's program could result in substantial increases in synthetics. It would be possible to increase industrial coal use and there is room for substantial increases in the utility sector if programs to replace oil and gas consumption are initiated.

Q. Jerry Eyster: What's the major decline in 1985 from the EPA analysis?

A. The main thing is with industrial coal use. We had to use a screwy industrial forecast but I think the utility is down by 50. That's saying they are going to defer the plants they don't need for load growth rather than bring them on to replace oil and gas. Net coal is down and exports are down too but the major reduction is industrial.

Figure 18

APPALACHIAN COAL PRODUCTION -- 1995

(10^6 tons/yr.)

	Previous	Variable	Full	Partial
Northern Appalachia				
Metallurgical	27	25	17	28
High Sulfur	73	90	124	100
Medium Sulfur	206	164	150	143
Low Sulfur	1	1	-	1
Total	307	279	290	271
Central Appalachia				
Metallurgical	159	146	123	157
High Sulfur	-	-	-	-
Medium Sulfur	25	25	24	25
Low Sulfur	21	20	17	20
Total	204	192	164	202

Figure 19

WESTERN COAL PRODUCTION -- 1995

(10^6 tons/yr.)

	Previous	Variable	Full	Partial
Western Northern Great Plains				
Medium Sulfur	167	180	264	142
Low Sulfur	427	386	329	400
	594	566	593	542
Rockies				
Medium Sulfur	12	19	9	17
Low Sulfur	92	76	53	90
	104	94	62	107
Southwest				
Medium Sulfur	2	2	2	2
Low Sulfur	46	46	43	46
	48	48	45	48

Figure 20

ICF CONSUMPTION FORECAST

(10^6 tons)

	1977	1985	1990	2000
Electric Utility	447	700	900	1,400
Industrial	60	90	125	250
Metallurgical	77	75	75	75
Residential/Commercial	7	5	5	5
Synthetics		0	5	25
Exports	60	50	65	100
Total	675	920	1,175	1,855

Figure 21

ICF PRODUCTION FORECAST

(10^6 tons)

	1977	1985	1990	2000
Appalachia	389	350	400	500
Midwest	147	175	250	415
Northern Great Plains	86	250	350	725
Rest of West	67	140	175	215
Total	689	920	1,175	1,855

ROCKY1:

AN ENERGY-ENVIRONMENT MODEL OF COAL AND ELECTRICITY SUPPLY

by

Robert L. Bivins
Charles D. Kolstad
Verne W. Loose
Robert E. Pendley
Myron L. Stein

Modeling and Economic Analysis
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ROCKY1:
AN ENERGY-ENVIRONMENT MODEL OF COAL AND ELECTRICITY SUPPLY

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ABSTRACT

This report describes a linear programming model of coal supply and electricity generation called ROCKY1. ROCKY1 is a national model built up from 57 coal demand (electricity supply) regions, 39 electricity demand regions, and 30 coal supply regions. The model satisfies a specified demand for electricity in each region by simulating coal production and transportation, electricity generation, and electricity transmission to minimize total costs subject to physical and environmental constraints.

The model is appropriate for a wide range of energy policy analyses. It can aid in the examination of the effects of national legislation governing air-quality standards and of restrictions on coal burning imposed by individual states. The method of incorporating restrictions on ambient concentrations of sulfur dioxide is unique to ROCKY1 and provides a basis for examination of the effects of coal conversion on western air quality.

INTRODUCTION

The Rocky Mountain States* of the American West frequently are cited as a potential "bread-basket" of domestic energy resources. This eight-state region contains about half of the national coal reserves, most of the high-grade uranium ores and prime-grade oil shale deposits, and very large geothermal energy reservoirs. Also, the area contributes significantly to national oil and gas production and has considerable potential for solar energy production. Understandably, the region has attracted much attention in long-range planning for energy resource development, with some future estimates showing substantial increases in the amount of energy extracted and exported from the region.

However, because of its small population and relative lack of development, the region also possesses another characteristic—a clean environment—that is of increasing value to the Rocky Mountain States and to the nation. Most of the air and water resources in the region have not suffered the degree of pollution found in more populated parts of the nation. The numerous national parks and monuments are still enjoyed mainly because of the high degree of visibility, clean water, and uncrowded conditions within their borders. The very attempts by national decision-makers and analysts to plan for future energy development in the region have given rise to numerous organized attempts to delay, advance, control, relocate, or, in some other manner influence the course of energy development in the region.

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*Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming.

Some of the issues that motivate such negative reactions are (1) the potential air, water, and land pollution caused by a substantial increase in coal mining and conversion; (2) the social, economic, and environmental effects of locating large energy projects near small western towns or fragile environments; (3) the potential conflict over water needs of western agriculture and proposed water-intensive energy projects such as oil shale processing or coal-based synthetic fuels plants; (4) the demands from Indian tribes for protection of their environments and control over their water and mineral resources; and (5) the controversy over the conflicting rights of states and the Federal Government to administer and enforce laws and regulations for developments located on lands owned by the Federal Government, but affecting environments and populations that are within a state's jurisdiction. These and other issues are well known and have been documented elsewhere.

Motivation for this analysis and modeling effort was based on a desire to conduct a detailed, quantitative investigation of a crucial aspect of the above issues; specifically, the effect of regional coal development and electricity generation on the region's environment and the (potentially) limiting effects that environmental protection measures—especially air-quality standards—might have on such development.

Coal and nuclear fuel usually are discussed as the primary domestic alternatives to oil and gas during the next few decades, with the relative reliance on these two resources depending largely on assumptions about the national commitment to develop nuclear power. In any case, consumption of coal in all regions of the nation is expected to increase.

Some national energy and environmental policy decisions imply a great reliance on western coal, as opposed to that from the East or the Midwest. For instance, the insistence that coal-fired electricity plants and industrial users of coal use best available control technologies (BACT) for cleaning flue gases and that they burn low-sulfur coal would increase reliance on western coal because about 80% of the nation's low-sulfur coal reserves lie in western coal seams. Intense development of synthetic fuels from coal also would increase reliance on western coal because the subbituminous and lignite coal required are located in western coal fields. However, it is not clear whether such reliance could be achieved under environmental standards such as the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act Amendments (CAAA) or other stringent environmental protection requirements.

A new model, ROCKY1,* was developed to examine these and other policy questions important to western energy development and environmental protection. ROCKY1 was developed—not in isolation from other efforts, but dependent on many others for data, concepts, and modeling techniques—because of two deficiencies in existing analysis models. First, no model available to us included environmental considerations as explicit constraints on model solutions, with the constraints capable of alteration for examining the relative effects of different levels of environmental protection. Second, no model available to us contained both the appropriate geographical resolution and an overall national supply-demand balancing system to insure that the regional effects studied were considered in the context of national energy policies.

ROCKY1 includes two explicit air-quality constraints and sufficient regional detail embodied in a national modeling framework to be used for the following kinds of analysis.

- To forecast coal and electric power development in the West under several different assumptions about national energy policies and growth projections.
- To examine the effects of imposing various levels of air-quality standards, especially in western air basins.

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*ROCKY1 is the current version of our model, as described herein. Other versions are anticipated and will be designated by other numbers.

- To examine the regional and national effects on coal mining, coal distribution, and electric power generation of national and state economic and environmental policies, such as BACT requirements, strip-and-ship legislation, severance taxes, CAAA/PSD regulations, visibility standards, and constrained nuclear development.

BASIC APPROACH OF ROCKY1

ROCKY1 is a linear programming (LP) model that consists of (1) a set of regions that consume coal for electricity generation and for other purposes and that produce electricity from various fuels, including coal; (2) a set of regions that produce coal of different types (distinguished by their heat and sulfur contents) at costs that increase with the quantity mined; (3) a set of regions that consume electricity; (4) a rail and barge coal transportation system that links coal supply and consumption regions; and (5) an electric transmission system that links electricity production and consumption regions.

Each activity simulated by the model has a cost associated with it; for example, the production of low-sulfur or high-Btu coal in a given region, the transportation of that coal to a distant region for use in an electricity generating station; and the transmission of the electricity to a consuming region. Subject to several constraints, the model seeks to satisfy demand at the lowest total cost for all these activities. Included among the contraints are sufficiency of production of various types of coal and restrictions on point-source and total sulfur emissions. Because the model is very disaggregate, the associated LP matrix is very large.

We had two reasons for using an LP approach. First, we wanted to simulate a decentralized decision-making system in which, to be competitive, consumers and producers of coal and electric power in different regions of the nation, facing different costs for delivering their services and under differing environmental constraints, must individually find ways of minimizing the costs of their services. This was felt to be a desirable representation of the coal supply industry, which consists of many suppliers and supply locations shipping a product that is variable in its primary qualities. The model thus examines the aggregate effects of a number of decentralized decisions. Second, we wanted to focus on the "supply-side" implications of meeting postulated levels of demand for coal and electricity. That is, we regard future national demand for these commodities as highly uncertain and subject to future decisions about long-term energy policy options.

The LP format is amenable to simulation of many policy-relevant options in energy supply; for example, the simulation of an established schedule for building nuclear power plants by using "build limits" (constraints in the LP); the simulation of a ban or moratorium on certain kinds of power plants (such as coal-fired plants) in environmentally sensitive areas; or the simulation of long-term coal production contracts for delivery to utilities on a "captive" basis by placing lower bounds on the amounts of coal shipped from a particular production region to a particular consumption region. These and other policies can be simulated, and the results can display the regional and national consequences of the particular policy being studied.

Conceptually, activation of the model begins by assuming an energy policy and specifying the annual quantities of electricity (kWh) and nonutility coal (Btu) that are demanded by each region. Demand for coal is specified for several nonutility purposes: coke and synfuels production, industrial use, residential and commercial use, and export. Coal is described physically by 8 categories of sulfur content and 5 categories of heat content; thus, 40 categories of coal may be produced and consumed.

Coal of sufficient heat content to meet the total demand must be transported to each demand sector, and sufficient coal of appropriate types must be produced in each production region to match the amounts shipped out. Each production region and each coal type has a "coal supply curve" that represents the increase in production cost per ton of coal as the demand for coal from that region rises. Thus, in the coal supply sector, the increasing cost of production from a particular coal reserve, the cost of transporting the coal to demand regions, and the fact that various users may be competing for the same coal combine to increase the price of coal and to insure that coal production occurs in regions that are economic for the overall decision about which type of coal is produced.

In the electric utility sector, several options exist for meeting electricity demand. Baseload electricity may be generated within the demand region, or it may be generated elsewhere and transmitted to the demand region. (Other modes of electricity demand, such as daily or seasonal peak demand, must be generated within the demand region.) There are many technological options for electricity generation at each supply region, including coal, nuclear, hydroelectric, and oil and gas steam and turbine plants. If existing generating capacity is not sufficient to meet demand, new capacity can be built at a cost. If coal-fired plants are chosen, more coal, sufficient to meet the energy conversion requirements, must be transported into the electricity supply region.

To illustrate the level of the model's aggregation, Figs. 1 and 2 show, respectively, the electricity demand and coal supply regions used in this study. Coal supply regions are not allowed to cross state boundaries, so we divided the fields shown in Fig. 2 into 30 regions, each within a state. To demonstrate more explicitly some of the options available in the model, Fig. 3 shows schematically how demand for electricity in southern California could be supplied. The options are generation in southern California, importation from northern California or the Pacific Northwest (probably from hydroelectric generation), or importation from the Four Corners area or the Southwestern States such as Arizona or Nevada (probably from coal-fired generation). For each analysis, the model finds the least expensive way of meeting demand in southern California. The model is constructed so that policy decisions, such as a moratorium on coal-fired plants in southern California, may be implemented easily, and the resulting shifts in the location and type of electric power generation can be examined readily.

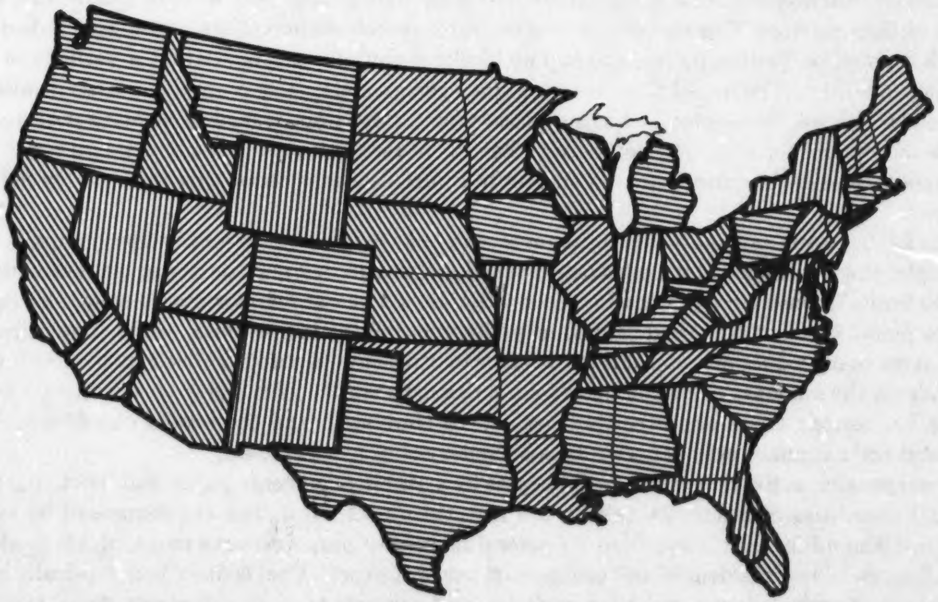
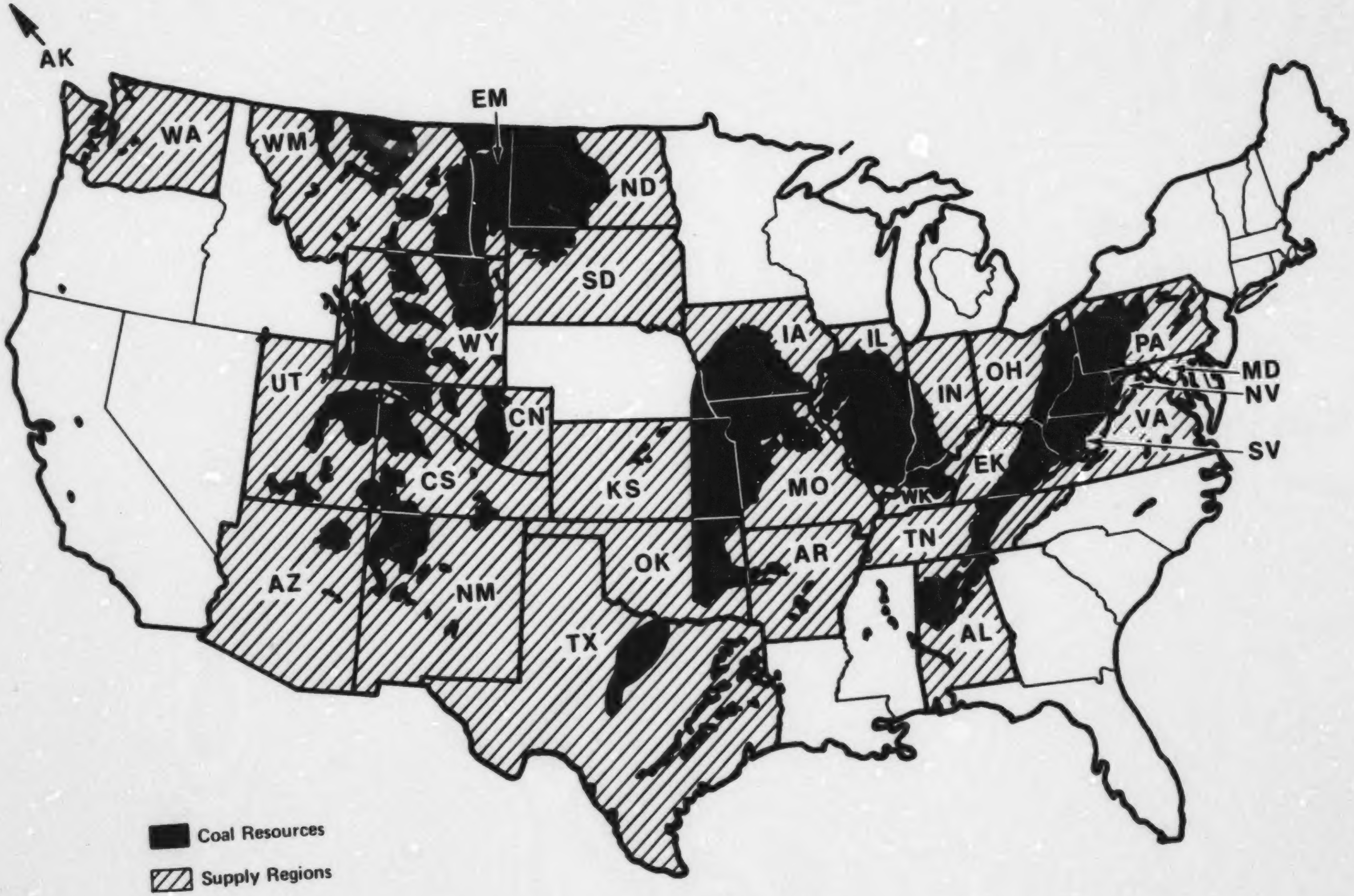


Fig. 1.

ROCKY1 electricity demand regions. Shading differences distinguish electricity demand regions. States of the same shade must be contiguous to be in the same region; for example, Washington and Oregon constitute a region, but Texas is a different region.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OH
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MD
NV
VA
SV
EK
WK
MO
AR
TN
AL
Coal Resources
Supply Regions

Fig. 2.
ROCKY1 coal supply regions.

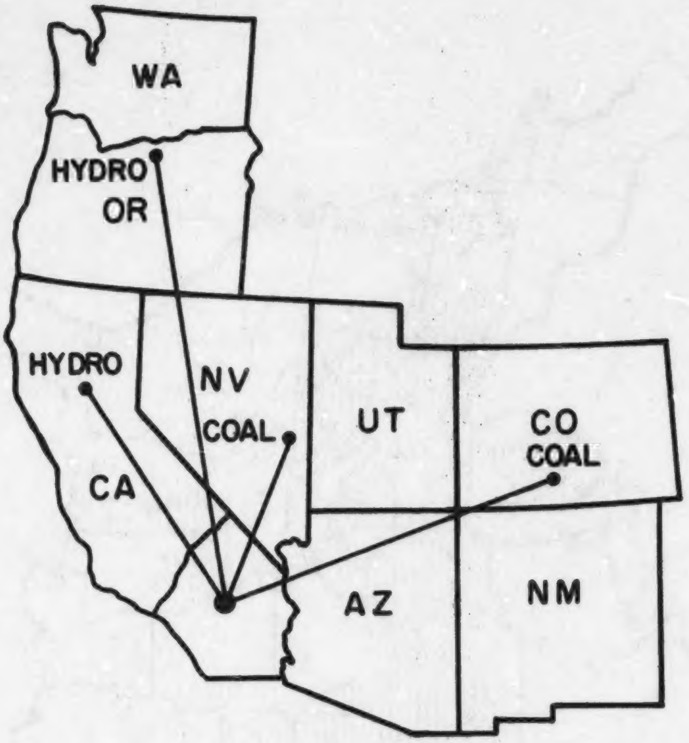

Fig. 3.
Potential sources of imported baseload electricity for the southern California market (illustrative only).

Like other models that simulate the coal and electric utility supply systems in a linear program, ROCKY1 has several limitations. It is not dynamic in that it does not make optimal decisions over time. Nor does it reflect the quantity-demanded response to price of electricity and nonutility coal. The decisions reached by the model are based only on selecting lowest cost alternatives; no regulatory or institutional considerations enter into decision-making except as they influence costs. The model contains parameter estimates (such as the capital costs of power plants in 1990) that are assumed to be perfectly known to decision-makers. The model does not consider estimates of uncertainties in these parameters.

The linear programming framework offers several features useful for analyses of coal and electricity supply. The cost-based model of coal supply curves and the cost-based decisions by the model about building new electric capacity are simulations of how decisions are made in these industries. Results from the model can be used as forecasts or baseline projections. The differences in results based on various assumptions about policies can be used as a sensitivity test of the impacts of the various policies. Obtaining these differences is especially convenient in the LP formulation, in which many constraints in the form of upper or lower bounds may be placed on variables, reflecting real-life considerations, such as the amount of new capacity from nuclear plants planned for a given year in a given electricity supply region. The implementation of these assumptions about actual situations makes the model more realistic and useful for policy analysis purposes.

UNIQUE FEATURES OF ROCKY1

ROCKY1 uses data bases and modeling concepts developed in several previous efforts, augmented and modified as required: the coal supply curves from the Project Independence Evaluation System used by the Federal Energy Administration (FEA), the National Coal Model developed by FEA, and the ICF Coal Model, which extended and modified the FEA model. These models were oriented toward providing national analyses of the coal supply and electricity generating situation, and were disaggregated approximately to a state-by-state basis with regional and national totals reported in the results.

A basic difference between ROCKY1 and these previous approaches is that electricity supply (coal consumption) regions of the Rocky Mountain States are further disaggregated as shown in Fig. 4. This was done not to achieve greater regional detail but to enable implementation of the other major difference in ROCKY1—the inclusion of specific air-quality constraints in the model structure. To do this, the electricity supply regions in the Rocky Mountain West were defined to be specific air basins, each with different air-quality standards. Basins were broken at state boundaries because air-quality regulations may differ from state to state.

As an example, Fig. 5 shows the division of Arizona into air basins. Five different parts of the state are distinguished, labeled AZ1 through AZ5. One part (AZ1) includes the largest metropolitan regions, where ambient conditions are currently worst and where additional pollution will be contested. The northwestern part of the state (AZ3) includes Grand Canyon National Park and is therefore subject to the PSD provisions of the CAAA. The northeastern part of the state (AZ2) includes the Hopi and Navajo Indian Reservations, which may be reclassified as Class I air-quality maintenance areas upon petition of tribal authorities to the Environmental

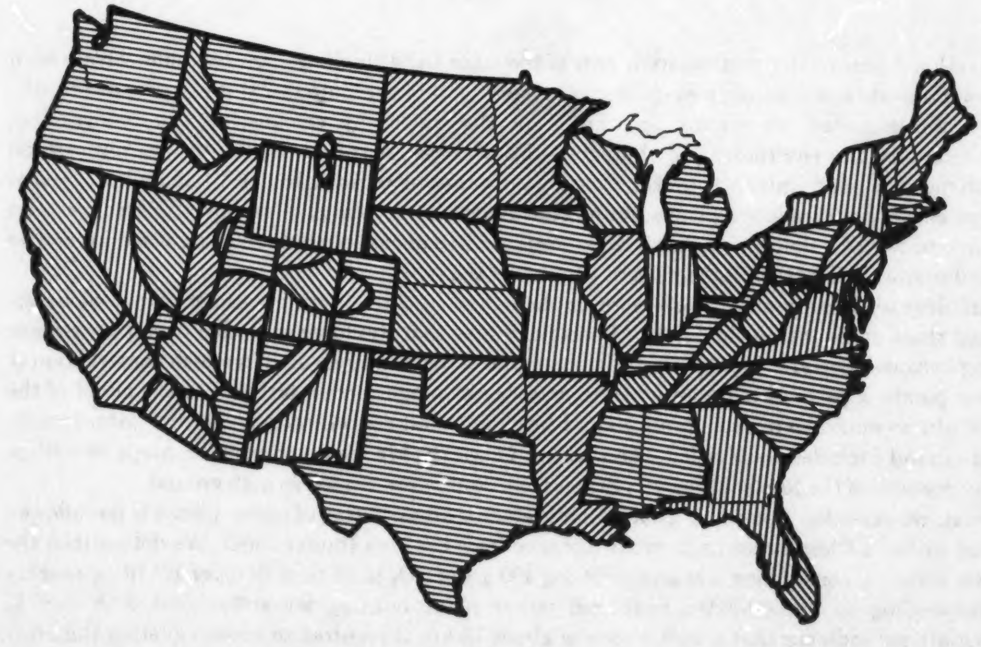

Fig. 4.
ROCKY1 coal demand regions. Shading differences distinguish coal demand regions. States of the same shade must be contiguous to be in the same region; for example, Washington and Oregon constitute a region, but Texas is a different region.

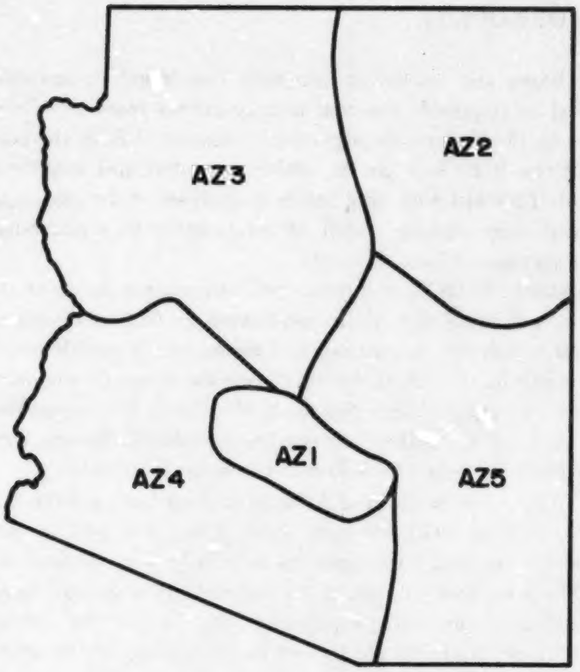

Fig. 5.
Arizona's air-basin regions.

Protection Agency. The southwestern part of the state (AZ4) includes mountainous terrain with national forests and roadless areas; the southeastern part of the state (AZ5) is high desert terrain.

We implemented air-quality constraints in the model by considering the topographic, demographic, and environmental characteristics of these areas and the limitations imposed on point-source sulfur emissions and ambient sulfur concentrations. ROCKY1 includes a point-source constraint developed by examining New Source Performance Standard (NSPS) limits on the amount of SO_2 that may be emitted per million Btu of coal consumed; this constraint can be varied to simulate more or less stringent versions of the NSPS.

Ambient air-quality constraints were implemented in the following manner. First, we determined those areas within the Rocky Mountain States that would be excluded from power-plant siting because they are "high ground." High ground is defined as an area in which construction of power plants is precluded because of the presence of rough terrain or because the effect of the stack plume would be unacceptable ground-level pollutant concentrations. For the latter reason, high ground included valleys less than 50 km in width. We used topographic maps to outline those portions of the Rocky Mountain States that would be excluded as high ground.

Next, we excluded Class I air-quality maintenance areas. Siting of power plants is not allowed either within a Class I area or for some distance from the area (buffer zone). We determined the buffer zones by considering a source emitting 400 g/s of SO_2 (0.15 lb of SO_2 per 10^6 Btu), roughly corresponding to a 2000-MWe coal-fired power plant burning low-sulfur coal with BACT. Calculations[1] indicate that a buffer zone of about 75 km is required to avoid violating the maximum permissible ground level SO_2 concentration for Class I areas of 5 $\mu g/m^3$. We outlined those areas that qualify as Class I (national parks and monuments, Indian reservations, etc.) and their buffer zones. To see the reduction in area available for coal-consuming facilities, examine Fig. 6,

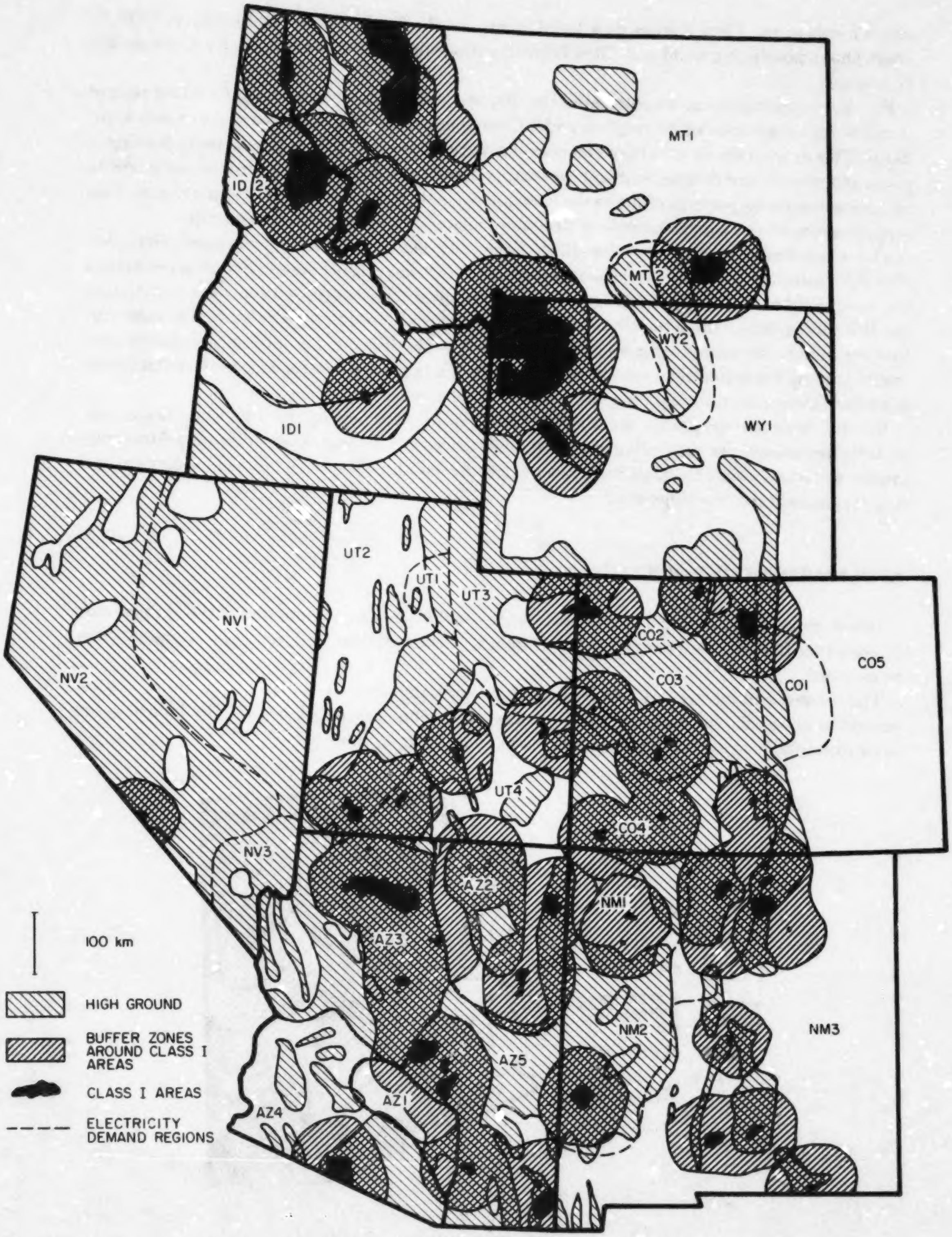
MT1
ID 2
MT 2
WY2
ID1
WY1
UT2
UT1
UT3
NV1
NV2
CO2
CO5
CO3
CO1
UT4
CO4
NV3
AZ2
NM1
AZ3
NM2
NM3
AZ5
AZ1
AZ4
100 km
HIGH GROUND
BUFFER ZONES AROUND CLASS I AREAS
CLASS I AREAS
ELECTRICITY DEMAND REGIONS

Fig. 6.
Class I areas with 75-km buffer zones.

which displays the Class I areas plus buffer zones for the Rocky Mountain States, and Fig. 7, which shows how high ground and Class I considerations limit the area available for development in Arizona.

For the remaining areas, we calculated the SO_2 carrying capacity (see Appendix A) for each of the ROCKY1 electricity supply regions under Class II and Class III air-quality maintenance standards. These calculations were based on previous work[1] that established the minimum spacing of power plants required to meet ambient air-quality standards. We then programmed the model to include a constraint corresponding to the carrying capacity of each electricity supply region. This numerical constraint can be varied to reflect other air-quality maintenance standards.

There are two advantages to handling air-quality constraints in this fashion. First, the ROCKY1 solution determines the least costly mix of coal that meets demand and does not exceed the air-quality standards specified for a particular analysis. This approach contrasts with that of the ICF model, which predetermines the proportions of coal types that must be used to meet certain air-quality standards. Our approach is more flexible because any level of air-quality contraint may be examined by a parameter change in the matrix generator and coal production is not forced toward certain coal types or toward certain regions.

Second, because air-quality constraints are formally included in the LP, when these constraints are binding we may calculate the shadow prices of the constraints and thus address two crucial questions about air quality: How much are we willing to pay for it? In what regions(s) will it first constrain coal development?

APPLICATIONS OF ROCKY1

Before describing the model in greater detail, we will discuss some examples of the applications intended for ROCKY1 so that the appropriateness of the variables and the levels of analysis can be assessed.

The model can be used to address four general problems: environmental policy issues, economic issues, facility location issues, and energy technology policy issues. The following are some examples of the most important questions that might be analyzed.

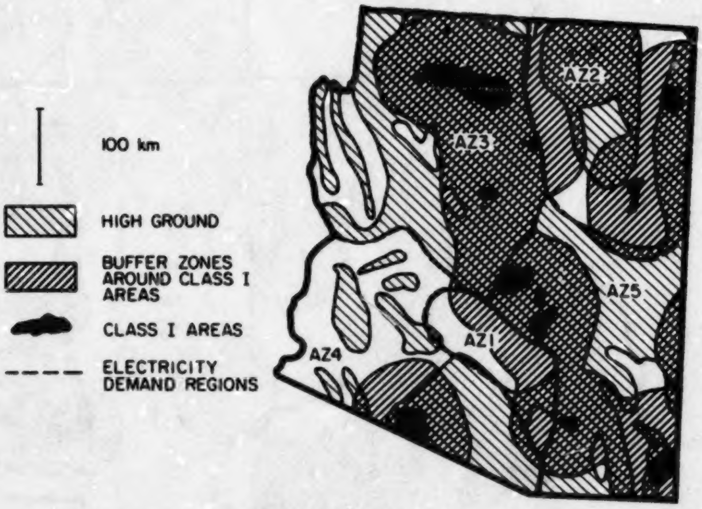

Fig. 7.
Arizona's high ground, Class I areas, and buffer zones.

Environmental Issues

- How binding are the different levels of air-quality standards on restricting growth of coal-consuming energy facilities? What is the cost of air-quality standards as measured by shadow prices?
- What is the effect of enforcing PSD standards on large portions of the West?
- What is the effect of requiring the use of BACT on all coal-burning power plants and industries? How does this change if low-sulfur coal must be used in combination with BACT?
- How large an effect would there be on area available for development (and on carrying capacity of air basins) as a result of excluding roadless areas and other proposed wilderness areas from coal and electricity production in the West?

Economic Issues

- What changes would occur in coal production and consumption patterns if one or more states in the region passed "strip-and-ship" legislation?
- What would be the effect on coal production patterns if large severance taxes were placed on coal production for export from the region? How would this affect costs to the consumer?
- What are the costs of air-quality regulations and how do these regulations contribute to the consumer's electricity costs?

Energy Facility Location Issues

- What is the distribution of coal mining, coal transportation, electric power generation, and electricity transmission within the region? What are the limitations on these distributions resulting from major policy options in environmental protection?
- What are the shifts in coal mining activity, regionally and nationally, resulting from BACT requirements? From BACT plus low-sulfur coal?
- What are the shifts in the location of coal-mining and electricity-generating facilities as a result of economic policies such as severance taxes?

Technology Policy Issues

- What would be the effects on coal and electricity production and costs, air quality, etc. of regional or national slowdowns in nuclear power plant construction?
- What would be the effects of policies of forced conversion to coal consumption by utilities and industries?
- What would be the effects on regional coal production, air quality, and coal costs to utilities of a program of intensive synthetic fuels production from coal and oil shale in the West?
- What would be the effects of changing the coal transportation system by building coal slurry pipelines from the West to the Midwest and to other users of western coal?

MATHEMATICAL STRUCTURE OF ROCKY1

ROCKY1 is a static (one-period) mathematical program of the transshipment type that minimizes the cost of meeting an exogenously specified inelastic demand for electricity and non-utility coal subject to physical and environmental constraints. It is particularly oriented toward coal-related policy questions. The uniqueness of ROCKY1 lies in its substantial geographic and environmental detail made possible by extensive preprocessing, thus eliminating obviously nonbasic variables before implementing the linear program.*

Indices

$i = 1,\ldots,30$: Coal Supply Regions (Fig. 2)

$j = 1,\ldots,57$: Coal Demand/Electricity Supply Regions (Fig. 4)

$k = 1,\ldots,40$: Coal Types (by sulfur and heat content)

$\ell = 1,\ldots,11$: Coal Consumption Sectors

$\ell = 1$ existing electricity generating plant without scrubbers
$\ell = 2$ existing electricity generating plant with retrofit scrubbers
$\ell = 3$ existing electricity generating plant with scrubbers
$\ell = 4$ new electricity generating plant with scrubbers
$\ell = 5$ lignite electricity generating plant
$\ell = 6$ metallurgical use
$\ell = 7$ industrial use
$\ell = 8$ synthetic fuels plant
$\ell = 9$ lignite gasification
$\ell = 10$ residential/commercial use
$\ell = 11$ export

$m = 1,\ldots,4$: Electricity Generating Mode

$m = 1$ baseload
$m = 2$ intermediate load
$m = 3$ seasonal peak
$m = 4$ daily peak

$n = 1,\ldots,8$: Noncoal Electricity Generating Sectors

$n = 1$ existing nuclear plant
$n = 2$ new nuclear plant
$n = 3$ existing hydroelectric facility
$n = 4$ new hydroelectric facility
$n = 5$ existing oil/gas steam plant
$n = 6$ new oil/gas steam plant
$n = 7$ existing oil/gas turbine plant
$n = 8$ new oil/gas turbine plant

---

*The problem size is 5000 rows by 20 000 columns. Using the APEX-III LP routine on a CDC-6600, approximate solution CPU time from a cold start is 35 min; from an approximate basis, 3.5 min.

Endogenous Variables

Coal

S_{ikp} : amount of k-type coal mined from the p-th step on the coal supply curve in region i (10^6 tons/yr)
$W_{ikk'}$: amount of k-type coal washed to k'-type coal in region i (10^6 tons)
$D_{j\ell k}$: amount of k-type coal consumed by sector ℓ in demand region j (10^{12} Btu)

Transportation

T_{ijk} : amount of k-type coal transported by rail from region i to region j (10^6 tons)
TB_{ijk} : amount of k-type coal transported by barge from region i to region j (10^6 tons)
$R_{jj'}$: amount of electricity exported from region j to region j' (10^9 kWh)

Electricity Generation

$O_{j\ell mk}$: amount of mode m electricity generated from k-type coal by ℓ-type plants in region j (10^9 kWh)
OP_{jnm} : amount of mode m electricity generated by n-type plants in region j (10^9 kWh)

Exogenous Variables: Policy, Fixed, Cost, and Intermediate Variables

The data sources for these variables are listed in Appendix B.

$a_{jj'}$: transfer coefficient giving fraction of emissions in region j contributing to ambient concentration in region j' (tons/yr to $\mu g/m^3$, fixed)*
AC_j : maximum allowed incremental ambient concentration of SO_2 in demand region j ($\mu g/m^3$, policy)
α_{ik} : heat content of type k coal produced in region i (10^6 Btu/ton, fixed)
$\bar{\alpha}_k$: average heat content of type k coal (10^6 Btu/ton, fixed)
$\beta_{\ell k}$: rate of sulfur emissions from burning type k coal in sector ℓ (lb/ton, fixed)
$CPM_{j\ell}$: capacity bound for type ℓ plants in region j (10^6 kW, policy)
CPN_{jn} : capacity bound for type n plants in region j (10^6 kW, policy)
$co_{j\ell mk}$: cost of operating type ℓ plants in region j in mode m using k coal (mills/kWh, cost)
cop_{jnm} : cost of operating type n plants in region j in mode m (mills/kWh, cost)
cr : cost of electricity transmission ($/kWh-mile, cost)
ct_{ij} : cost of rail transport of coal from region i to region j ($/ton, cost)
ctb_{ij} : cost of barge transport of coal from region i to region j ($/ton, cost)
cs_{ikp} : cost of mining type k coal from the p-th step of the coal supply curve in region i ($/ton, cost)
cw : cost of washing coal ($/ton, cost)
$d_{jj'}$: transmission distance between region j and region j' (miles, fixed)
δ_j : maximum incremental output of sulfur allowed in region j (lb/yr, policy)
$\epsilon_{jj'}$: efficiency of electricity transmission from region j to region j' (fixed)
η : efficiency of washing coal (fixed)
$\theta_{j\ell}$: maximum permissible amount of SO_2 that may be emitted by sector ℓ for a given thermal input in region j (lb/10^6 Btu, policy)
EDM_{jm} : total demand for mode m electricity in region j (10^9 kWh, intermediate)
ELC_j : total demand for electricity in region j (10^9 kWh, policy)
γ_{jm} : fraction of total demand for electricity in region j required in mode m (policy)
$h_{j\ell m}$: heat rate of type ℓ plants operating in mode m in region j (10^3 Btu/kWh, fixed)
$\lambda_{j\ell}$: conversion factor used to convert the amount of production to capacity needed for type ℓ plants in region j (10^9 kWh/yr to 10^6 kW, fixed)

---

*Set to zero for all $j \neq j'$ pending further development of visibility constraints.

ν_{jn} : conversion factor used to convert the amount of production to capacity needed for type n plants in region j (10^9 kWh/yr to 10^6 kW, fixed)

$ps_{j\ell}$: point-source SO_2 emissions limitation for sector ℓ in region j (lb/10^6 Btu, policy)

ρ_k : sulfur content of type k coal (lb/10^6 Btu, fixed)

$TD_{j\ell}$: total demand for nonutility coal by sector ℓ of region j (10^{12} Btu, policy)

Objective Function

We seek to minimize the following objective function, which consists of sums over the indices of the costs of: coal mining, coal washing, coal transport by rail, coal transport by barge, electricity generation from coal, electricity generation from fuel other than by coal, and electricity transmission.

Minimize, over S, W, D, T, TB, R, O, and OP

$$\Big\{ \sum_i \sum_k \sum_p S_{ikp} \cdot cs_{ikp} + \sum_i \sum_k W_{i,k,k+1} \cdot cw + \sum_i \sum_j \sum_k \left[(T_{ijk} \cdot ct_{ij}) + (TB_{ijk} \cdot ctb_{ij}) \right]$$

$$+ \sum_j \sum_{\ell=1}^{5} \sum_m \sum_k O_{j\ell mk} \cdot co_{j\ell mk} + \sum_j \sum_n \sum_m OP_{jnm} \cdot cop_{jnm} + \sum_j \sum_{j'} R_{jj'} \cdot cr \cdot d_{jj'} \Big\} \ .$$

Constraints

Coal shipments must satisfy demand.

$$\sum_\ell D_{j\ell k} \leq \sum_i \alpha_{ik}(T_{ijk} + TB_{ijk}) \ .$$

Coal supply must be adequate for coal shipments.

$$\sum_j (T_{ijk} + TB_{ijk}) \leq \sum_p S_{ikp} + \eta \sum_{k'} W_{ikk'} - \sum_{k'} W_{ikk'} \ .$$

Nonutility coal demand must be met.

$$TD_{j\ell} \leq \sum_k D_{j\ell k} \ .$$

Utility coal demanded must equal utility coal used.

$$D_{j\ell k} = \sum_m h_{j\ell m} O_{j\ell mk} \ .$$

Electricity generated must not exceed the electric capacity upper bound.

$$\sum_m \sum_k \lambda_{j\ell m} \ O_{j\ell mk} \leq CPM_{j\ell} \ .$$

and

$$\sum_{m} \nu_{jnm}\, OP_{jnm} \leq CPH_{jn} \ .$$

Electricity demand by mode must be met by generation and imports of electricity. Only baseload electricity is transported. Electricity demand by mode m (EDM_{jm}) is a fixed fraction of total demand ($\gamma_{jm}ELC_j$). For m = 1,

$$\sum_{\ell=1}^{5} \sum_{k} O_{j\ell mk} + \sum_{n} OP_{jnm} + \left(\sum_{j'} R_{j'j}\epsilon_{j'j} - \sum_{j'} R_{jj'} \right) \geq EDM_{jm}$$

For m = 2, 3, and 4,

$$\sum_{\ell=1}^{5} \sum_{k} O_{j\ell mk} + \sum_{n} OP_{jnm} \geq EDM_{jm} \ .$$

Emissions of sulfur must not violate ambient air-quality standards.

$$\sum_{j} \sum_{k} \sum_{\ell} \frac{a_{j'j}\beta_{\ell k}D_{j\ell k}}{\bar{\alpha}_k} \leq AC_{j'} \ .$$

Point source environmental standards must be met in terms of average SO_2 emissions per 10^6 Btu coal burned.

$$\sum_{k} \left(\frac{\beta_{\ell k}}{\bar{\alpha}_k} - ps_{j\ell} \right) D_{j\ell k} \leq 0 \ .$$

APPENDIX A

AIR QUALITY METHODOLOGY

Emissions of SO_2 by all coal-burning activities are considered to contribute to ambient concentrations of SO_2. To convert emissions to ambient concentration levels, one considers "worst conditions"—a stagnation period during which emissions accumulate locally and violate the 24-hour standard. Assuming worst conditions, the SO_2 "carrying capacity" C_r for a particular region is

$$C_r = A_r\bar{\chi}\, L/t \ ,$$

where L is the height of the mixing layer (500 m), t is the duration of the stagnation condition (48 h), $\bar{\chi}$ is the ambient SO_2 concentration limit, and A_r is the area of the region under consideration. This carrying capacity approach is described in more detail in Hinman and Leonard.[1]

To express C_r (for each of the electricity supply regions shown in Fig. 4) as a function of $\bar{\chi}$, we first must determine A_r. The quantity A_r is that area within each region in which it is feasible to locate generating capacity and is set equal to the physical area of the region minus that area excluded because it is either Class I (plus buffer zone) or high ground. For these reasons, we excluded roughly 60% of the area of the Rocky Mountain States.

APPENDIX B

DATA SOURCES FOR EXOGENOUS VARIABLES

DATA OBTAINED FROM OTHERS

We obtained data for the following variables from the second version of the National Coal Model,[2] compiled under the auspices of the FEA.

- Existing electricity generating capacity as of 1975, except for the Rocky Mountain States.
- Existing coal reserves
- Coal supply curves
- Cost and efficiency of washing coal
- Cost and efficiency of electricity transmission
- Cost of rail and barge transport of coal
- Sulfur and heat content of coal
- Rate of SO_2 emissions
- Heat rates of electricity generating plants
- Modal split of electricity demand by baseload, intermediate, seasonal peak, and daily peak
- Total demand for nonutility coal

DATA OBTAINED BY ROCKY1 PROJECT STAFF

Existing Capacity of Electricity Generating Plants in the Rocky Mountain West

These data were compiled from the April 1, 1976, report[3] of the Western Systems Coordinating Council, which presents existing capacity of the systems as of December 31, 1975.

Cost of Operating Coal-Using Plants

For existing facilities we have applied the economic concept of sunk costs, implying that the cost of operation consists solely of variable costs—fuel, operation, and maintenance. For facilities to be constructed, fixed costs associated with avoidable capital expenditures are added to these variable costs.

The concept of levelization has been applied to the capital and operation and maintenance costs for all facilities. The levelization formulas used are those published in the Electric Power Research Institute (EPRI) Technical Assessment Guide (see p. V-23).[4] These formulas and the parameters and coefficients used in them are intended to implement the Revenue Requirements approach.[4] The fixed-charge rate used in the calculations was based on the factors displayed on p. V-9 of the EPRI Technical Assessment Guide. We made two changes in these factors: the weighted cost of capital was adjusted to reflect real, not nominal, dollars and tax preferences were excluded. These adjustments resulted in a levelized annual fixed-charge rate of 11.1%. Table B-I lists the capacity factors used in the calculations.

To introduce regional variation in construction costs for electricity generating plants, we used the capital cost estimates published by the Energy Information Administration's Annual Report to Congress for 1977.[5] We established a correspondence relationship to associate ROCKY1 electricity supply regions with the DOE regions for which capital cost estimates are given and obtained the operating cost estimates presented in Tables B-II to B-VI.

Because of the low value of the fuel and the quantity a standard electric power plant would burn per kWh of output, new lignite plants would likely be built only at the source of the few lignite deposits in the country. New oil and gas turbine plants are assumed to be equally costly throughout the contiguous 48 states. For these reasons, no regional variation is built into the cost estimates presented in Table B-VII for new lignite and oil and gas turbine plants.

The existing capacity of electricity generating plants as of December 31, 1975, was obtained from the WSCC report.[8] The breakdown by electricity supply region is shown in Table B-VIII.

The amount of sulfur emitted by various coal consumers varies according to the quantity of sulfur in the input coal, the completeness of burning of the coal, and the degree of treatment of the stack gases. Table B-IX lists, for each coal-consumption index, the ratio of sulfur emitted to sulfur contained in the input coal.

TABLE B-I

CAPACITY FACTORS FOR ELECTRICITY GENERATING TECHNOLOGIES USED IN ROCKY1

Capacity Factors For Coal Plants	
Existing plant without scrubbers	0.75
Existing plant with retrofit scrubbers	0.65
Existing plant with scrubbers	0.65
New plant with scrubbers	0.65
Lignite Plant	0.65

Capacity Factors For Noncoal Plants	
Existing nuclear	0.57
New nuclear	0.57
Existing hydroelectric	0.75
New hydroelectric	0.75
Existing oil/gas steam	0.60
New oil/gas steam	0.60
Existing oil/gas turbine	0.11
New oil/gas turbine	0.11

TABLE B-II

LEVELIZED ANNUAL COSTS OF EXISTING ELECTRICITY GENERATING PLANTS

Plant Type (All DOE Regions)	ROCKY1 Technology Index	1990 Costs in 1975 Dollars (mills/kWh)			
		Capital Cost	Operation and Maintenance Cost	Fuel Cost	Total Cost[c]
Coal, without scrubbers	$\ell=1$	[a]	1.77	[b]	1.77
Coal, with retrofit scrubbers	$\ell=2$	2.55	4.33	[b]	6.88
Coal, with scrubbers	$\ell=3$	---	4.33	[b]	4.33
Nuclear	$n=1$	---	1.22	5.31	6.53
Hydroelectric	$n=3$	---	0.70	---	0.70
Oil/gas steam	$n=5$	---	0.90	32.89	33.79
Oil/gas turbine	$n=7$	---	2.75	39.40	42.15

---

[a] No capital costs are applied to existing facilities.

[b] Coal fuel cost obtained endogenously in ROCKY1.

[c] Exclusive of fuel cost for all coal plants.

TABLE B-III

LEVELIZED ANNUAL COST OF A NEW COAL PLANT WITH SCRUBBERS

DOE Region	ROCKY1 Technology Index	1990 Costs in 1975 Dollars (mills/kWh)		
		Capital Cost	Operation and Maintenance Cost	Total Cost
1	$\ell=4$	10.74	4.33	15.07
2	$\ell=4$	11.36	4.33	15.69
3	$\ell=4$	10.22	4.33	14.55
4	$\ell=4$	9.68	4.33	14.01
5	$\ell=4$	10.61	4.33	14.94
6	$\ell=4$	9.72	4.33	14.05
7	$\ell=4$	10.53	4.33	14.86
8	$\ell=4$	10.12	4.33	14.45
9	$\ell=4$	10.95	4.33	15.28
10	$\ell=4$	10.45	4.33	14.78

---

[a] Exclusive of fuel cost, which is determined endogenously in ROCKY1.

TABLE B-IV

LEVELIZED ANNUAL COST OF A NEW NUCLEAR STEAM PLANT

DOE Region	ROCKY1 Technology Index	1990 Costs in 1975 Dollars (mills/kWh) Capital Cost	Operation and Maintenance Cost	Fuel Cost	Total Cost
1	n=2	15.45	1.22	5.31	21.98
2	n=2	18.01	1.22	5.31	24.54
3	n=2	15.45	1.22	5.31	21.98
4	n=2	12.67	1.22	5.31	19.20
5	n=2	15.45	1.22	5.31	21.98
6	n=2	14.12	1.22	5.31	20.65
7	n=2	14.89	1.22	5.31	21.42
8	n=2	14.89	1.22	5.31	21.42
9	n=2	15.67	1.22	5.31	22.20
10	n=2	17.56	1.22	5.31	24.09

TABLE B-V

LEVELIZED ANNUAL COST OF A NEW OIL/GAS STEAM PLANT

DOE Region	ROCKY1 Technology Index	1990 Costs in 1975 Dollars (mills/kWh) Capital Cost	Operation and Maintenance Cost	Fuel Cost	Total Cost
1	n=6	8.76	0.90	32.89	42.55
2	n=6	9.25	0.90	32.89	43.04
3	n=6	8.30	0.90	32.89	42.09
4	n=6	7.88	0.90	32.89	41.67
5	n=6	8.64	0.90	32.89	42.43
6	n=6	7.92	0.90	32.89	41.71
7	n=6	8.57	0.90	32.89	42.36
8	n=6	8.24	0.90	32.89	42.03
9	n=6	11.66	0.90	32.89	45.45
10	n=6	8.51	0.90	32.89	42.30

TABLE B-VI

LEVELIZED ANNUAL COST OF A NEW HYDROELECTRIC PLANT

		1990 Costs in 1975 Dollars (mills/kWh)			
DOE Region	ROCKY1 Technology Index	Capital Cost	Operation and Maintenance Cost	Fuel Cost	Total Cost
1	n=4	6.76	0.70	---	7.46
2	n=4	5.74	0.70	---	6.44
3	n=4	7.94	0.70	---	8.64
4	n=4	7.10	0.70	---	7.80
5	n=4	7.60	0.70	---	8.30
6	n=4	8.79	0.70	---	9.49
7	n=4	8.28	0.70	---	8.98
8	n=4	5.58	0.70	---	6.28
9	n=4	10.47	0.70	---	11.17
10	n=4	3.72	0.70	---	4.42

TABLE B-VII

LEVELIZED ANNUAL COST OF A NEW LIGNITE PLANT AND A NEW OIL/GAS TURBINE PLANT

	1990 Costs in 1975 Dollars (mills/kWh)			
ROCKY1 Technology Index	Capital Cost	Operation and Maintenance Cost	Fuel Cost	Total Cost
ℓ=5	11.52	4.33	[a]	15.85[b]
n=8	35.62	2.75	39.4	77.71

---

[a] Fuel cost for lignite plants determined endogenously in ROCKY1.

[b] Exclusive of coal cost.

TABLE B-VIII

EXISTING ELECTRICITY GENERATING CAPACITY IN THE ROCKY MOUNTAIN STATES

	Existing without Scrubbers	Existing with Scrubbers	Capacity (MW)		
			Oil/Gas Steam	Oil/Gas Turbine	Hydroelectric
Arizona					
Phoenix/Tucson	---	---	1863	1347	232
Navajo	1500	120	---	---	1101
Yavapai	---	---	---	---	546
Yuma	---	---	75	160	---
Cochise	---	---	---	114	---
Colorado					
Denver/Colorado Springs	1421	---	246	50	124
Routt	---	---	---	---	---
Grand Junction	75	---	---	19	480
Durango	236	---	34	19	7
Eastern Plains	670	---	54	328	---
Idaho					
Boise/Idaho Falls	---	---	---	50	1314
Nez Perce	---	---	---	---	---
Montana					
Northern Plains/Helena	---	---	---	28	1361
Big Horn	0.510	---	70	---	285
Nevada					
Eastern Great Basin	---	---	---	8	---
Carson City	---	---	466	58	9
Las Vegas	1.800	---	288	171	1554
New Mexico					
San Juan	2.172	0.330	30	---	---
Rio Grande/Gallup	---	---	395	20	---
Little Texas	---	---	---	---	15
Utah					
Salt Lake City	0.180	---	104	22	150
Western Great Basin	0.007	---	---	12	---
Uintah	0.171	---	---	---	---
Kaiparowitz	0.415	---	---	---	---
Wyoming					
Bighorn	---	---	16	11	197
Casper/Powder River	2.483	---	---	---	---

TABLE B-IX

SULFUR EMISSIONS FROM COAL CONSUMPTION SECTORS

Coal-Consumption Index ℓ		Ratio
1	Existing plant without scrubbers	0.95
2	Existing plant with retrofit scrubbers	0.15
3	Existing plant with scrubbers	0.10
4	New plant with scrubbers	0.10
5	Lignite plant	0.10
6	Metallurgical use	1.0
7	Industrial use	1.0
8	Synthetic fuels plant	0.02
9	Lignite gasification	0.05
10	Residential/commercial use	1.0
11	Export	0

REFERENCES

1 George Hinman and Ellen Leonard, "Air Quality and Energy Development in the Rocky Mountain West," Los Alamos Scientific Laboratory report LA-6674 (September 1977).

2. ICF Incorporated, "The National Coal Model: Description and Documentation" (Washington, D.C., 1976).

3. Western Systems Coordinating Council, "Reply to FPC Order 383-4, Docket R-362, Reliability and Adequacy of Service" (Salt Lake City, Utah, 1976).

4. Electric Power Research Institute, "Technical Assessment Guide" (Palo Alto, California, 1978).

5. Energy Information Administration, "Annual Report to Congress for 1977" (US Government Printing Office, Washington, D.C., 1977), Vol. II, Appendix B, pp. B80-92.

Page 7*

Question: Hoff Stauffer. Have you checked your air basins with EPA? Would they agree with your air basins in the Rocky Mountain region?

Answer: No, we did not derive our air basins in the same manner as EPA and we have not checked with them for agreement. Air quality control regions in the West are not particularly appropriate for this type of analysis.

Page 10*

Question: Hoff Stauffer. Do you have two separate emission standards?

Answer: Yes, there is an emission standard for each plant and an aggregate regional standard.

Question: Jerry Eyster. Then you could treat PSD questions because you have an incremental pollution loading formulation for each region?

Answer: Yes, we also intend to translate ambient air quality constraints into visibility standards.

Question: Hoff Stauffer. What you call ambient air quality constraints in terms of the model are the limits of aggregate emissions and you calculate those limits externally using the dispersion model?

Answer: Charles Kolstad. Not quite. We translate emissions into ambient concentrations and place constraints on ambient concentrations.

Question: Jerry Eyster. Do emissions vary by regions such that, depending on wind and other conditions, you get different loadings?

Answer: That's right.

Question: Hoff Stauffer. So aggregated emissions by region are multiplied by a constant function of meteorology to translate into impacts?

Answer: Right.

*Page numbers refer to applicable areas of the text

Question: Dan Klein. In your analysis of plumes, I am troubled by the distances set up for the worst possible case. EPA has said that without scrubbing a 1,000 megawatt plant needs a 50-75 mile buffer zone in a Class I area but that with full scrubbing of compliance coal a 6-10 mile buffer zone is adequate. Do you assume a 1,000 megawatt plant and, if not, how do you reconcile the differences in modeling techniques?

Answer: The strength of source is an important factor. We assume a 400 gram-per-second emission rate which is a very clean coal plant of the 2,000 megawatt size or a several hundred thousand barrel per day oil shale plant. Also, I must say that there is not much agreement in the meteorological community concerning pollutant transport in the complex terrain areas we examine.

Question: Dan Klein. If the buffer zone is proportional to the size of the plant and the efficiency of the technology could you build a smaller plant within 75 miles of a Class I area?

Answer: Yes.

Question: Dan Klein. So by defining 2,000 megawatt plants you are overstating the size of the buffer zones experienced in the real world?

Answer: Yes.

Question: Dan Klein. Are you using EPA air dispersion models for calculations involving Class I areas?

Answer: Not directly, although we do use a model similar to the VALLEY model.

Question: Hoff Stauffer. Given the variability in coal, the variability of SO_2 emissions from a scrubbed plant goes up as the averaging unit goes down. Therefore, a plant can have a peak concentration measured over a 3-hour period much higher than over a 24-hour period. Thus, a 3-hour limitation can be much more binding than a 24-hour limitation.

Answer: This is true although the 3-hour limit is higher than the 24-hour limit. It is our view that the 24-hour limit is most binding although this position could certainly change.

Question: Hoff Stauffer. Does your model allow a plant currently meeting NSPS to install a scrubber on low sulfur coal to sneak under the limit of the NSPS?

Answer: New facilities are forced to use the best available control technology.

Page 11*(cont)

Question: Hoff Stauffer. But the best available control technology is usually a political decision. Didn't you model it as 0.8 pounds?

Answer: We modeled it as 90% removal of everything for all new plants.

Question: Hoff Stauffer. Can your new plants switch from a high to a low sulfur coal?

Answer: That could happen if low sulfur coal were cheaper or if an environmental constraint forced it.

Question: Hoff Stauffer. So theoretically a plant, instead of changing locations because of an environmental constraint, might instead decide to burn low sulfur instead of high sulfur coal?

Answer: That could happen in the East because of variability in the sulfur content of coal but is less likely to happen in the West where most coal is low sulfur.

Question: Jerry Eyster. Since you assumed a 2,000 megawatt plant, would going to smaller plants result in bigger areas?

Answer: Yes, our assumptions could be defined as a limiting case.

Question: Dan Klein. How do you measure pollution concentrations in areas where you have bad areas in the midst of good areas?

Answer: We assume that we have a box surrounding the area to keep all the pollution in and then simply add up concentrations within the area.

Question: Jerry Eyster. Why do you use a nuclear capacity factor of only 0.57%?

Answer: It's a point estimate of data on all nuclear plants as reported by Edison Electric Institute.

Question: Jerry Eyster. Their more recent information averaged over 0.65%. That will go down this year because of Three Mile Island. A recent report by the Nuclear Regulatory Commission sets it in the low 60s with a standard deviation of 8% points.

Page 15*

Question: Andy Van Horn. Do you force all new coal plants to have scrubbers? I presume that there are places in the West where you could burn complying coal without building scrubbers.

Answer: The analyses we have done include BACT so our new plants have scrubbers.

Question: Andy Van Horn. In what year are these new plants coming on line?

Answer: In 1990.

Question: Dan Klein. By separating lignite plants from other new plants does that imply that they do or do not have scrubbers? Also, by not separating subbituminous plants are you implying that they have the same capital requirements and O&M costs as bituminous plants?

Answer: The same capital costs apply to bituminous and subbituminous plants but different costs apply to lignite plants.

Question: Dan Klein. Do lignite plants have scrubbers?

Answer: Yes, but we want to give new plants burning low sulfur coal the option of not having scrubbers.

Question: Dan Klein. Does synfuels include gasification or liquids?

Answer: We are talking only of liquefaction.

Question: Hoff Stauffer. Are the matrix generator and report writer written in FORTRAN?

Answer: Yes.

Question: Hoff Stauffer. How long does the LP run on a benchmark machine?

Answer: On the 6600 it takes about 30 minutes from a cold start and about 3 minutes from an approximate basis. The cold start includes generating the matrix, solving the LP, and writing the report. We have not experienced any bottlenecks using the 6600 but if we do we can move to a faster machine.

Question: Hoff Stauffer. Have you looked into using network algorithms for optimization?

Answer: No, APEX has been very satisfactory.